December 17, 2021

Executive Officer Richard Corey
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Phillips 66 – Application No. B0241 for Three Low-Carbon Fuel Standard Tier 2 Fuel Pathways

Communities for a Better Environment and the Natural Resources Defense Council ("Commenters") offer the following comments on the Low Carbon Fuel Standard ("LCFS") Tier 2 Pathway Application No. B0241 submitted by Phillips 66.

On December 9, 2021, California Air Resources Board ("CARB") staff published a recommendation to certify Phillips 66's application for three fuel pathways for Renewable Diesel. Two of these pathways are for soybean oil. One assumes oil received by rail in Rodeo from the U.S. Midwest, and the other assumes oil received first in Louisiana before being transported via barge to Rodeo. The third pathway is for canola oil transported by ship, first to the Port of Vancouver, then to Southern California, and finally to Rodeo. Phillips 66's application is for a provisional pathway,[1] which allows for certification based only a few months of data, compared to the usual requirement of 24 months.[2]

In all three pathways, the credit-generating fuels would be produced by a processing unit at the Phillips 66 Rodeo facility that is likely unpermitted and is undergoing investigation by the Bay Area Air Quality Management District ("BAAQMD"). Commenters request that CARB hold the application and withhold certification until the resolution of the related and ongoing BAAQMD investigation; as well as the conclusion of the ongoing Contra Costa County ("County") California Environmental Quality Act ("CEQA") permit process for the larger conversion of the facility to biofuel production, which implicates issues relevant to the requested Tier 2 certification.

Now is a particularly critical time for action on this matter, as similar biofuel conversions involving hydroprocessed fats and oils become more numerous across the state. If this pathway is prematurely approved, Commenters are concerned this may encourage additional, unpermitted conversions to produce biofuels at individual units, supported by the promise of LCFS credit incentives. Holding the application until the investigation and CEQA processes are completed will ensure that Phillips 66's generated LCFS credits, and those from potential future projects,

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[1] The Staff report refers to Application No. B0241 as a "provisional application" to be certified. Provisional applications are based on 17 CCR §95488.9(c), which are available when "existing facilities that can demonstrate a process change has been implemented, based on at least three months of operational data" so that they can start generating credits using a "provisionally-certified" carbon intensity.

[2] 17 CCR §95488.7(a)(1)

are consistent with local air district regulations, as well as the comprehensive review of related projects and impacts that CEQA is designed to facilitate.

1. The Fuels Produced Under These Pathways Would Be Produced by a Likely Unpermitted Air Source Under Current BAAQMD Investigation

The Lifecycle Analysis that accompanies Phillips 66's application package is explicit that the fuels would be produced using a former diesel hydrotreater, specifically "Unit 250", that first began producing renewable diesel in early April 2021.[3]

This unit appears to have undergone an unpermitted conversion. On July 30, 2021, the Natural Resource Defense Council and other advocates submitted a letter to BAAQMD Chief Executive Officer notifying the agency that this conversion – from a diesel hydrotreater to a renewable diesel hydroprocessing unit – had been implemented without a BAAQMD permit as appears to be required.[4] In September, BAAQMD staff responded saying that it had begun to investigate and would begin on-site investigations and an engineering review of the Rodeo facility.[5]

Available evidence indicates this unpermitted conversion at Unit 250 was essentially a dry run for the larger conversion that Phillips 66 has proposed for Rodeo, which is currently under CEQA review by the County. The company has admitted as much, with the head of the company's refining segment calling this conversion part of the "learning curve" before getting to the "big projects" in an earnings call.[6] Yet the "Rodeo Renewed" application for the larger conversion of the refinery does not include Unit 250. Commenters have requested that Contra Costa County revise its draft Environmental Impact Report (DEIR) to include the related Unit 250 conversion, such that CARB should hold off on the Tier 2 application until the County makes a decision whether to do so.[7] Even if it does not, the CEQA review for the Rodeo

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[3] (S&T)[2] Consultants Inc., CARB LCFS Fuel Pathway Report Renewable Diesel Prepared for Phillips 66 Company, pp. 1, Dec. 6, 2021.
, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0241_report.pdfhttps://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0241_report.pdf (accessed Dec 14, 2021) [hereinafter CARB LCFS P66 Pathway Report 2021]

[4] *See* letter "Re: Phillips 66 refinery (Air District plant no. 21359) - possible unpermitted modifications", July 30, 2021. Included as Attachment A.

[5] Sanicola, Laura, EXCLUSIVE California Bay area regulators probe Phillips 66 refinery work –email, Sept. 15, 2021. *Reuters*. https://www.reuters.com/business/energy/exclusive-california-bay-area-regulators-probe-phillips-66-refinery-work-email-2021-09-15/ (accessed Dec. 16, 2021)

[6] *See* earnings call referenced in McGurty, Janet, "Phillips 66 Starts Up First Renewable Diesel Unit at Rodeo Refinery," April 30, 2021, *Platt's S&P Global.* https://www.spglobal.com/platts/en/market-insights/latest-news/oil/043021-phillips-66-starts-up-first-renewable-diesel-unit-at-rodeo-refinery (accessed Dec. 16, 2021) [hereinafter McGurty]. We have also obtained a transcript of the call 'Mr. Herman stated on the call with respect to the Unit 250 project, "It's a learning curve around some of the products -- how to handle the product coming off the unit and everything before we get to the big projects."')

[7] *See* letter "Re: Phillips 66 Rodeo Renewed Project (File No. LP20–2040) – comments concerning draft environmental impact report," Dec. 17, 2021. Included as Attachment B.

Renewed project will potentially provide valuable detailed information on the feedstocks used by Phillips 66, which is a substantive requirement in the LCFS application process.[8]

The LCFS regulations make it clear that CARB's Executive Officer has the authority to "restrict, suspend, or invalidate credits" that are "generated... in violation of other laws, statutes, or regulations." Title 17, CCR, §95495(a) et seq. Commenters urge CARB to exercise this discretion to ensure that LCFS credits generated are in compliance with air district regulations. Approval of Phillips 66's LCFS pathway application should be placed on hold until BAAQMD's investigation has been completed. In addition, consideration of the Tier 2 application would wait until the Rodeo Renewed CEQA process has completed, since CEQA contemplates comprehensive review of all related aspects of a project; and the substantive issues under review in the County's CEQA process are highly germane to ensuring an accurate assessment of the carbon intensity under this Tier 2 application. The application should wait until the CEQA process has completed.

2. Conversion of the Diesel Hydrotreater to Produce Renewable Diesel Likely in Violation of Air District Regulations

As stated in NRDC's letter from July, there remains no indication that Phillips 66 applied for an Authority to Construct or a Title V revision for Unit 250 to process crop oil feedstocks. As stated by Phillips 66, this was not simply a replacement of feedstock – this required a conversion of the hydrotreater in order to process the food crop oil feedstocks.[9] In its application for Authority to Construct and Title V revision submitted May 21, 2021, Phillips 66 labeled Unit 250 as a "DHT/Renewable Diesel" unit,[10] despite the lack of any permit application for this renaming.

Even if the unit did not require physical conversion, the facility should have applied for an updated permit to operate, under BAAQMD Regulation 2-1-233. Such a change would constitute an *alteration*, defined as "[a] change in the method of operation of.... a source which may affect emissions." Such an alteration "require[s] a permit to operate, and may require permit conditions, *whether or not the alteration results in an emission increase*" (emphasis added). While Regulation 2-1-233 continues to provide a limited exemption ("A change in process stream composition is not an alteration if the source's description in the permit and permit conditions allow for the change in process stream composition"), this exemption does not

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[8] *See* 17 CCR §95488.7 (2)(A)(2) ("For fuels utilizing agricultural crops for feedstocks, the [fuel production process in the Life Cycle Analysis Report] shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-processing (such as drying or oil extraction)")

[9] McGurty ("Specifically, on the company's first quarter earnings call on April 30, Phillips 66 CEO Greg Garland stated, "In April, the company completed its diesel hydrotreater conversion, which will ramp up to 8,000 b/d (120 million gallons per year) of renewable diesel production by the third quarter of 2021." Robert Herman, head of the company's refining segment, added, "So on Unit 250, we started it up here early in April after turnaround to convert the unit to run soybean oil, and so we're running the clean soybean oil out there. And unit came up first time and has run well.")

[10] Application For Authority to Construct Permit And Title V Operating Permit Revision For Rodeo Renewed Project Phillips 66 Company San Francisco Refinery (District Plant No. 21359 And Title V Facility # A0016), pp. 15, May 2021. Included as Attachment C.

apply to Phillips 66's conversion because Unit 250 was plainly intended to process only petroleum feedstocks when it was permitted as S-460. As stated in the statement of basis for its 2004 Title V revision, "S-460 will hydrotreat diesel cuts from the various processing units, including the S-350 crude unit (Unit 267) and the S-300 crude/coker (Unit 200)...."[11] As a result, this conversion should have required a permit application under 2-1-233 and potentially under Title V. Phillips 66's application should, at least, be held until these permitting issues have been resolved.

3. Failure to Disclose All Project Components in Contra Costa County Draft Environmental Impact Review (DEIR) Likely Violates CEQA

Under CEQA, an EIR must describe the proposed project being reviewed. Guidelines, §15124. CEQA defines "project" as "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." Guidelines § 15378(a); Pub. Res. Code § 21065. CEQA forbids segmenting a project into separate actions in order to avoid environmental review of the "whole of the action." Furthermore, CEQA requires the lead agency to consider an entire project at the earliest possible stage, including all reasonably foreseeable phases of the project. CEQA also requires the County to evaluate the whole of the impacts, and its contributions to cumulative impacts in the EIR. By failing to consider all of the segments of the project as a whole, or by failing to take into account the whole of the foreseeable cumulative impacts, the County will have failed to comply with its CEQA requirements. Accordingly, courts have found that even if an EIR is adequate in all other respects, the use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency did not proceed in a manner required by law. Id. *San Joaquin Raptor*, 27 Cal.App.4th at 730 (citation omitted).

a. Unit 250 – Converted Diesel Hydrotreater

Contra Costa County improperly disclaimed any connection between Unit 250, the converted diesel hydrotreater, and the project described in the Rodeo Renewed Project ("Project") Draft Environmental Impact Report (DEIR).[12] However, actions taken to produce alternative fuels in Unit 250 are functionally part of the Project, and therefore needed to be disclosed as such. These actions both involved physical changes within the refinery, integrated with and functionally interdependent with the proposed Project operation. This undisclosed action expands the scope and severity of potential impacts resulting from the Project, which must be disclosed in the DEIR.

Thus, CARB should refrain from certifying an LCFS pathway for renewable diesel produced by the hydrotreater in question until the County has corrected the omission of the

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[11] Bay Area Air Quality Management District, Final Permit Evaluation and Statement of Basis for Major Facility Review Permit Reopening - Revision 1 for ConocoPhillips - San Francisco Refinery Facility #A0016, Dec. 2004, pp. 48. https://www.baaqmd.gov/~/media/files/engineering/title-v-permits/a0016/a0016_2004-12_reopen_03.pdf (accessed Dec. 16, 2021).

[12] Contra Costa County, Rodeo Renewed Project Draft Environmental Impact Report, Oct. 2021. https://www.contracosta.ca.gov/DocumentCenter/View/72880/Rodeo-Renewed-Project-DEIR-October-2021-PDF (accessed Dec. 16, 2021) [hereinafter Rodeo Biofuel Conversion DEIR].

hydrotreater from the DEIR and completed all subsequent impacts analysis in compliance with CEQA.

b. Port of Los Angeles (Port of LA) Marine Oil Terminal and Wharf Improvement Project (MOT Project) at Berths 148-151

The Life Cycle Analysis report reveals a feedstock route that was undisclosed in the Contra Costa County DEIR and potentially a connection to another Phillips 66 project at the Port of Los Angeles (Port of LA).[13] [14] The report describes "The [canola oil] shipment that was received was *first sent to Southern California* for some of the oil to be off loaded and then moved north to Rodeo for unloading the remainder of the cargo. This accounts for the long transportation distance"[15] (emphasis added).

Not only was this route not disclosed in the Contra Costa County DEIR, Phillips 66 is also taking contemporaneous action to advance the Marine Oil Terminal (MOT) and Wharf Improvement Project (MOT Project) at the Port of Los Angeles (Port of LA) Berths 148-151 in Southern California. This proposed Port of LA project also includes a request for consideration of a new 20-year entitlement (with two potential 10-year additional options) in Wilmington, an environmental justice community.

In the MOT Project, Phillips 66 proposes to demolish the timber wharf at Berths 150-151, replacing it with a new concrete wharf and associated equipment, for the stated purpose of compliance with safety standards. Yet it is clear from the MOT Project documents and larger circumstances that the MOT project may have a purpose, in part, of advancing the Rodeo Biofuel Project. Most notably, the draft Initial Study and Negative Declaration describes its operations at the marine terminal as "load[ing] and unload[ing] oil commodities products such…naphthas, gasoline/gasoline blend stocks, diesel and jet fuels, and distillate blend stocks, *as well as renewables and renewable feedstocks*…" (emphasis added).[16]

Thus, CARB should refrain from certifying fuels that may be produced from feedstock transported in connection to yet another undisclosed component that involves another environmental review happening in Los Angeles.

Thank you for your consideration,

Connie Cho

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[13] CARB LCFS P66 Pathway Report 2021, pp. 1-4, 7-9 Consultants Inc., CARB LCFS Fuel Pathway Report Renewable Diesel Prepared for Phillips 66 Company, pp. 1-4, 7-9, Dec. 6, 2021,

[14] City of Los Angeles Harbor Department (LAHD), Draft Initial Study/ Mitigated Negative Declaration for Berths 148-151 (Phillips 66) Marine Oil Terminal (MOT) and Wharf Improvement Project (proposed Project) at the Port of Los Angeles (Port), Nov. 2021. https://kentico.portoflosangeles.org/getmedia/d9b76ad6-9242-46e2-91b5-a7def9ac4e1f/Berths-148-151-P66-MOTEMS-Draft-IS-MND (accessed Dec 14, 2021) [hereinafter LAHD P66 IS/Neg Dec 2019].

[15] CARB LCFS P66 Pathway Report 2021, pp. 5.

[16] LAHD P66 IS/Neg Dec 2019, pp. 8.

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Attachment A

July 30, 2021 Letter to BAAQMD Regarding Possible Unpermitted Modifications of Unit 250 at Phillips 66 Rodeo Refinery

COMMUNITY ENERGY RESOURCE • NATURAL RESOURCES DEFENSE COUNCIL • RODEO CITIZENS ASSOCIATION • SUNFLOWER ALLIANCE

July 30, 2021

Via electronic mail (jbroadbent@baaqmd.gov)

Jack Broadbent
Chief Executive Officer
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

Re: Phillips 66 refinery (Air District plant no. 21359) - possible unpermitted modifications

Dear Mr. Broadbent:

We are writing to alert you to information indicating that the Phillips 66 Rodeo refinery appears to have engaged in facility modifications without a required permit from the Air District. We are hopeful that you will take appropriate action to investigate and address this, and will keep us informed of your progress.

Specifically, on the company's first quarter earnings call on April 30, Phillips 66 CEO Greg Garland stated, "In April, the company completed its diesel hydrotreater conversion, which will ramp up to 8,000 b/d (120 million gallons per year) of renewable diesel production by the third quarter of 2021." Robert Herman, head of the company's refining segment, added, "So on Unit 250, we started it up here early in April after turnaround to convert the unit to run soybean oil, and so we're running the clean soybean oil out there. And unit came up first time and has run well."[1]

A project of this nature plainly requires authority to construct from the District pursuant to Regulation 2-1-301, as changing the nature of the feedstock for the hydrotreater - and any steps performed to achieve that "conversion" during the referenced turnaround - would qualify as an alteration pursuant to Regulation 2-1-233. Additionally, this change would appear to require, at minimum, an application for a minor Title V permit revision under Regulation 2-6-406, since the facility's current Title V permit references only petroleum as a feedstock. The change may also require review under the California Environmental Quality Act (CEQA), as it does not fall into any exempt category set forth in Regulation 2-1-312.

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[1] *See* "Phillips 66 Starts Up First Renewable Diesel Unit at Rodeo Refinery," *Platt's S&P Global* April 30, 2021, *available at* https://www.spglobal.com/platts/en/market-insights/latest-news/oil/043021-phillips-66-starts-up-first-renewable-diesel-unit-at-rodeo-refinery. We also have obtained a transcript of the call.

However, we see no indication on the District's website that the facility has applied for authority to construct or a Title V revision, or any other type of authorization for this change at Unit 250. We have reviewed documents received in response to a Public Records Act request for permits applied for and/or issued at the facility, but have found no reference in those documents to the hydrotreater project referenced on the earnings call.

We further note that the Unit 250 project is conceptually part and parcel of the Rodeo Renewed project to convert the refinery to biofuel production, and was in fact specifically referred to by Mr. Herman as a dry run for the larger conversion. Mr. Herman stated on the call with respect to the Unit 250 project, "It's a learning curve around some of the products -- how to handle the product coming off the unit and everything before we get to the big projects." However, the application for authority to construct submitted in May 2021 in connection with the Rodeo Renewed project does not include changes to this unit.

We would add, in this regard, that the permit application for the Rodeo Renewed project does not include a request to increase in hydrogen production at the Air Liquide facility, even though it is fairly clear based on our analysis that additional hydrogen generation capacity will be necessary to produce the volume of product contemplated in the project application. We hope the District will ensure that this omission does not result in additional unpermitted activity at the refinery.

These are not mere paperwork concerns on our part. The conversion of the refinery from processing crude to processing biofuel feedstocks will likely result in additional air emissions associated with the increased inputs of hydrogen necessary to process soybean oil and other renewable feedstocks. In particular, the new soy oil feed requires increased per-barrel hydrogen inputs for deoxygenation, boosting exothermic reaction heat and thus the risk of runaway reactions. Hydrogen-related runaway reactions already result in recurrent flaring, according to Phillips 66 causal reports pursuant to Air District Regulation § 12-12-406. The choice of product slate generated from the soy feedstock can also potentially increase emissions, another reason it is essential that the District fully evaluate the feedstock shift. Members and constituencies of the signatory organizations will be directly impacted by these pollutant increases.

We request that you please review the situation and advise us what steps you plan to take to ensure that Phillips 66 complies with Air District regulations in any activities associated with its biofuel conversion project. If we have somehow overlooked a valid permit for the project at Unit 250, please let us know that as well.

Very truly yours,

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Attachment B

December 17, 2021 Comments on Draft Environmental Impact Report for Phillips 66 Rodeo Renewed Project

ASIAN PACIFIC ENVIRONMENTAL NETWORK • BIOFUELWATCH • CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE • CENTER FOR BIOLOGICAL DIVERSITY • CITIZEN AIR MONITORING NETWORK • COMMUNITIES FOR A BETTER ENVIRONMENT • COMMUNITY ENERGY RESOURCE • EXTINCTION REBELLION SAN FRANCISCO BAY AREA • FOSSIL FREE CALIFORNIA • FRIENDS OF THE EARTH • INTERFAITH CLIMATE ACTION NETWORK OF CONTRA COSTA COUNTY • NATURAL RESOURCES DEFENSE COUNCIL • RAINFOREST ACTION NETWORK • RICHMOND PROGRESSIVE ALLIANCE • RODEO CITIZENS ASSOCIATION • SAN FRANCISCO BAYKEEPER • STAND.EARTH • SUNFLOWER ALLIANCE • THE CLIMATE CENTER • 350 CONTRA COSTA

December 17, 2021

Via electronic mail (gary.kupp@dcd.cccounty.us)[1]

Gary Kupp
Senior Planner
Contra Costa County
Department of Conservation and Development
30 Muir Rd
Martinez, CA 94553

Re: Phillips 66 Rodeo Renewed Project (File No. LP20–2040) – comments concerning draft environmental impact report

Dear Mr. Kupp:

Asian Pacific Environmental Network, Biofuelwatch, California Environmental Justice Alliance, Center for Biological Diversity, Citizen Air Monitoring Network, Communities for a Better Environment, Community Energy reSource, Extinction Rebellion San Francisco Bay Area, Fossil Free California, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rainforest Action Network, Richmond Progressive Alliance, Rodeo Citizens Association, San Francisco Baykeeper, Stand.Earth, Sunflower Alliance, and The Climate Center, 350 Contra Costa (collectively, Commenters) appreciate this opportunity to submit comments concerning the Contra Costa County's Draft Environmental Impact Report (DEIR) for the proposed Phillips 66 refinery (Refinery) Rodeo Renewed project (Project).

For reasons explained in these comments, the DEIR falls far short of the basic requirements of the California Environmental Quality Act (CEQA), Pub. Resources Code §

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[1] The sources cited in this Comment are being sent separately via overnight mail to the County on a thumb drive.

21000 et seq. An EIR is "the heart of CEQA."[2] "The purpose of an environmental impact report is to provide public agencies and the public in general with detailed information about the effect which a proposed project is likely to have on the environment; to list ways in which the significant effects of such a project might be minimized; and to indicate alternatives to such a project." Pub. Res. Code § 21061. The EIR "is an environmental 'alarm bell' whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return. The EIR is also intended 'to demonstrate to an apprehensive citizenry that the agency has, in fact, analyzed and considered the ecological implications of its action.' …." *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("Laurel Heights I"). A project's effects include all indirect impacts that are "reasonably foreseeable." CEQA Guidelines, § 15064, subd. (d). An indirect environmental impact is "reasonably foreseeable" when "the [proposed] activity is capable, at least in theory, of causing" a physical change in the environment. Union of Medical Marijuana Patients, Inc. v. City of San Diego (2019) 7 Cal.5th 1171, 1197. Courts have analyzed whether it is "reasonably foreseeable" that a project will cause indirect physical changes to the environment in a variety of factual contexts, including changes to off-site land use, lifecycle impacts, and displaced development impacts. *County Sanitation Dist. No. 2 v. County of Kern* (2005) 127 Cal.App.4th 1544. See *Save the Plastic Bag Coalition v. City of Manhattan Beach* (2011) 52 Cal.4th 155, 174; *Muzzy Ranch Co. v. Solano County Airport Land Use Com*. (2007) 41 Cal.4th 372, 382-383. As explained below, the DEIR fails adequately to describe the Project's significant effects, let alone mitigate them.

The DEIR fails to meet these legal standards. The proposed Project would, if built, be the largest biofuel refinery in the world.[3] A conversion of an existing refinery of this size is unprecedented and untested in California, implicating unknown impacts on operational safety, the agricultural land use systems supplying the feedstock, air emissions, and California's climate goals in the transportation sector, among other things. The law requires more than the limited and uninformative document the County has produced. And the community in and around Rodeo who will have to live with the Project, and everyone else potentially affected by it, deserve better.

Its key deficiencies, described in the sections below, include the following:

- *Incorrect baseline.* The assessment of impacts in the DEIR, and its definition of the no project alternative is grounded in an assumption that in the absence of the proposed conversions, the Refinery would continue processing crude oil at historic levels. This assumption is unsupported and contrary to fact. Available information makes clear that closure of the Santa Maria refinery, the source of petroleum feedstock for the Rodeo refinery, is inevitable with or without the Project.
- *Faulty project description.* The DEIR fails to disclose essential information regarding the proposed biofuel processing operations. This includes key information about feedstocks, as well as about the proposed refining process – such as processing

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[2] *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("*Laurel Heights I"*).
[3] "Phillips 66 Plans World's Largest Renewable Fuels Project," Phillips 66 Corporate Website, *available at* https://www.phillips66.com/newsroom/rodeo-renewed.

chemistry, hydrogen production and input requirements (a major emissions generator) and refining temperature and pressure (which implicates process upset risks),– that are essential to an assessment of the proposed new operations on the surrounding community. It also fails to disclose actions connected to the Project that should have been considered together with it.

- *Failure to consider safety impacts.* The County ignored available information indicating a possible heightened threat of process upsets associated with processing of biofuel feedstocks, creating greater risk for workers and the community.
- *Failure to fully evaluate air quality impacts.* The DEIR, having failed to describe the new proposed process chemistry, fails as well to describe the air emissions impact of that process chemistry on air quality. In particular, the County ignored available information that the new feedstocks risk an increase in flaring and accidental releases; and failed to evaluate the differing air emissions impacts of various proposed feedstocks and product slates. The County also failed to assess the acute short-term hazards from flaring, confining itself to addressing longer-term pollution.
- *Failure to fully evaluate marine impacts.* The DEIR fails to adequately address the contemplated drastic increase in the amount of feedstock crossing through the marine terminal, including the risk of spills involving Project feedstocks for which impact and cleanup methods are poorly understood; as well as the impact of that increase on air quality, recreation, aesthetics, wildlife, and other public resources.
- *Failure to consider the environmental impacts of land use changes.* The Project will require importation of an unprecedented volume of food crop feedstocks such as soy oil. Yet the DEIR entirely neglects to consider the environmental impact of this massive diversion of food crop oils on land use – including conversion of forest land to cropland, and incentivizing increases in palm oil production.
- *Inadequate analysis of climate impacts.* The DEIR failed to consider the indirect impacts of the proposed Project on California's climate goals. Full analysis of climate impacts must consider not just emissions from Project operations, but also the impact of a large influx of combustion fuel on climate goals for the transportation sector.
- *Inadequate discussion of hazardous contamination.* The Project will have a limited lifetime given that California's climate commitments lead away from combustion fuel. Accordingly, the DEIR should have considered the environmental impacts associated with decommissioning the Refinery site, which is almost certainly heavily contaminated with toxics. Additionally, the DEIR inadequately evaluated the impact of Project construction and operation on ongoing efforts to remediate and monitor hazardous waste contamination.
- *Deficient cumulative impacts analysis.* Remarkably, even though the DEIR was issued simultaneously with the DEIR for the very similar biofuel conversion project at the Marathon Martinez refinery, the DEIR makes no effort at all to evaluate the cumulative impact of those two projects together – not to mention other biofuel conversion projects – on key issues such as land use impact and regional air quality.
- *Deficient 'no project' alternative analysis.* Without the proposed Project, the Refinery would not continue processing crude at historic levels. Accordingly, the DEIR should have considered the environmental impacts associated with subsequent legal requirements for site decommissioning.

- *Deficient project alternatives analysis.* The DEIR improperly fails to consider an electrolytic "green" hydrogen alternative, even though it considered such an alternative for the very similar Marathon Martinez conversion project. Additionally, it improperly considers the various alternatives for reducing the Project's impact separately rather than together. The option of reducing the scope of the Project can and should have been considered together with the option of not expanding crude throughput over the wharf. The DEIR also defines the Project objectives so narrowly as to distort the consideration of alternatives.

The County had abundant information concerning all of these subjects at its fingertips that would have facilitated the type of robust analysis required for this Project, but chose to ignore it in the DEIRs. Commenters requested in their January 26, 2021 CEQA scoping comments on the Notice of Preparation (Scoping Comments) that these topics be considered, and provided voluminous documentation concerning each.[4] The County chose to ignore it all in drafting the DEIR, resulting in a woefully deficient document.

The deficiencies we have identified are too pervasive and deep to be corrected merely by making changes in a final EIR. In order to ensure that the public has full information and opportunity to comment upon, the County must re-circulate a revised DEIR providing fully-documented analysis of all of the issues addressed in this comment (as well as the Scoping Comments). It is unavoidable that addressing the deficiencies identified in these comments in a manner that complies with CEA will necessarily require addition of "significant new information." CEQA Guidelines § 15088.5.[5]

This Comment document includes and incorporates the previously-submitted Scoping Comments as well as the expert report of Greg Karras accompanying this document as an appendix. All sources cited in this document have are being provided electronically to the County under separate cover.

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[4] Biofuelwatch, Community Energy reSource, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, Sierra Club, Stand.Earth, Sunflower Alliance, and 350 Contra Costa, Phillips 66 Rodeo Renewed Project – comments concerning scoping: File LP20–2040 (Jan. 27, 2021), available at Contra Costa County Department of Conservation & Development Community Development Division. Appendix A: Notice of Preparation and Public Comments, https://www.contracosta.ca.gov/DocumentCenter/View/72907/Appendix-A--NOP-and-Public-Comments-PDF (accessed Dec. 10, 2021).

[5] The regulations implementing CEQA, 14 CCR 15000 *et seq.*, are cited herein as the CEQA Guidelines.

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APPENDIX A: Karras, G, *Changing Hydrocarbons Midstream*; technical report and accompanying supporting material appendix for Natural Resources Defense Council, San Francisco, CA, June 2021 (Karras, 2021a).

APPENDIX B: Karras, G, *Unsustainable Aviation Fuel;* technical report for Natural Resources Defense Council, San Francisco, CA, August 2021 (Karras, 2021b).

APPENDIX C: Karras, G, *Technical Report in Support of Comments Concerning Rodeo Renewed Project*; technical report prepared for Natural Resources Defense Council, San Francisco, CA, December 2021 (Karras, 2021c).

I. STATEMENTS OF INTEREST

The interest of each of the Commenters in the DEIR and Project impacts is as follows:

Asian Pacific Environmental Network (APEN) is an environmental justice organization with deep roots in California's Asian immigrant and refugee communities. Since 1993, APEN has built a membership base of Laotian refugees in Richmond and throughout West Contra Costa County. We organize to stop big oil companies from poisoning our air so that our families can thrive.

Biofuelwatch provides information, advocacy and campaigning in relation to the climate, environmental, human rights and public health impacts of large-scale industrial bioenergy. Central to the Biofuelwatch mission is promoting citizen engagement in environmental decision making in relation to bioenergy and other bio-based products – including bioenergy-related decisions on land use and environmental permitting.

California Environmental Justice Alliance (CEJA) is a statewide, community-led alliance that works to achieve environmental justice by advancing policy solutions. We unite the powerful local organizing of our members across the state in the communities most impacted by environmental hazards – low-income and communities of color – to create comprehensive opportunities for change at a statewide level through building community power. We seek to address the climate crisis through holistic solutions that address poverty and pollution, starting in the most over-burdened communities.

Center for Biological Diversity is a national, nonprofit conservation organization with more than 1.3 million members and online activists dedicated to the protection of endangered species and wild places, public health, and fighting climate change. The Center works to secure a sustainable and healthy future for people and for all species, great and small, hovering on the brink of extinction. It does so through science, law, and creative media, with a focus on protecting the lands, waters, and the climate.

Citizen Air Monitoring Network is a community group started in 2016 in Vallejo. Our mission is to make sure the air quality in our community is healthy for all. Vallejo is situated in the middle of five refineries, and we are deeply concerned about the impact of their operation.

Communities for a Better Environment is a California nonprofit environmental justice organization with offices in Northern and Southern California. For more than 40 years, CBE has been a membership organization fighting to protecting and enhancing the environment and public health by reducing air, water, and toxics pollution. Hundreds of CBE members live, work, and breathe in Contra Costa County and the area surrounding the Marathon Refinery. The Northern California office is located in Contra Costa County.

Community Energy reSource offers independent pollution prevention, environmental justice, and energy systems science for communities and workers on the frontlines of today's climate, health, and social justice crises. Its work focuses on assisting communities with a just transition from oil refining and fossil power to clean, safe jobs and better health.

Extinction Rebellion San Francisco Bay Area (XRSFBay) is a local chapter of the global movement to compel business and government to address the climate and ecological crisis. We use nonviolent direct action, theater and art to bring the message that we are running out of time to prevent climate disaster and it is necessary to Tell the Truth, Act Now, Go Beyond Politics and Create a Just Transition for all beings in the Bay Area and beyond.

Fossil Free California is a nonprofit organization of climate justice volunteers. Many are members of the two largest public pension funds in the country, CalPERS and CalSTRS, which continue to invest in fossil fuel companies. Fossil Free California works to end financial support for climate-damaging fossil fuels and promotes the transition to a socially just and environmentally sustainable society. Together with allied environmental and climate justice organizations, we mobilize grassroots pressure on CalPERS and CalSTRS, as well as other public institutions, to divest their fossil fuel holdings.

Friends of the Earth is a national nonprofit environmental organization which strives for a more healthy and just world. Along with our 2 million members and activists we work at the nexus of environmental protection, economic justice and social justice to fundamentally transform the way our country and world value people and the environment. For more than 50 years, we have championed the causes of a clean and sustainable environment, protection of the nation's public lands and waterways, and the exposure of political malfeasance and corporate greed. Our current programs focus on promoting clean energy and solutions to climate change; ensuring a healthy, just and resilient food system where organic is for all; protecting marine ecosystems and the people who depend on them; and transforming our financial, economic and political systems.

Interfaith Climate Action Network of Contra Costa County County (ICAN) is a non-profit environmental justice organization working group of California Interfaith Power and Light, whose offices are in Oakland. CA. The mission of ICAN is to inform and educate faith and non-faith communities and individuals about how to mitigate climate change, advocate with leaders of BILPOC communities before government agencies, industry and other organizations that need to hear our collective voices. They are committed to centering the voices of those most impacted by industry, particularly the communities close to the refineries in Contra Costa County.

Natural Resources Defense Council (NRDC) is a nonprofit environmental membership organization that uses law, science, and the support of more than 440,000 members throughout the United States to ensure a safe and healthy environment for all living things. Over 2,200 of NRDC's members reside in Contra Costa County, some of those in the City of Rodeo. NRDC has a long-established history of working to ensure proper oversight of refining activities and minimize their carbon footprint and other environmental impacts, and ensure that biofuels are produced in a sustainable manner.

Rainforest Action Network (RAN) preserves forests, protects the climate and upholds human rights by challenging corporate power and systemic injustice through frontline partnerships and strategic campaigns. RAN works toward a world where the rights and dignity of all communities are respected and where healthy forests, a stable climate and wild biodiversity are protected and celebrated. RAN is a collaborative organization that challenges corporate power and exposes institutional systems of injustice in order to drive positive systemic change.

Richmond Progressive Alliance is an association of members in Richmond, California, with the explicit goal of taking political decision-making back from corporations and putting power in the hands of the people. The RPA mobilizes people in support of progressive policies and candidates, often in alliance with other local groups.

Rodeo Citizens Association is a non-profit environmental organization with the primary purpose of providing a means for the citizens of Rodeo to address issues of local concern with respect to health, safety, and the environment. Currently, RCA's primary activity is focused on promoting responsible use of land and natural resources around the community and to engage in community outreach activities involving education and awareness of environmental protection issues impacting the region.

San Francisco Baykeeper (Baykeeper) has worked for more than 25 years to stop pollution in San Francisco Bay and has more than five thousand members and supporters who use and enjoy the environmental, recreational, and aesthetic qualities of San Francisco Bay and its surrounding tributaries and ecosystems. San Francisco Bay is a treasure of the Bay Area, and the heart of our landscape, communities, and economy. Oil spills pose one of the primary threats to a healthy Bay, and environmental impacts from increased marine terminal activity directly threaten Baykeeper's core mission of a Bay that is free from pollution, safe for recreation, surrounded by healthy beaches, and ready for a future of sea level rise and scarce resources. San Francisco Baykeeper is one of 200 Waterkeeper organizations working for clean water around the world. Baykeeper is a founding member of the international Waterkeeper Alliance and was the first Waterkeeper on the West Coast. Baykeeper also works with 12 Waterkeepers across California and the California Coastkeeper Alliance.

Stand.earth is a San Francisco-based nonprofit that challenges corporations and governments to treat people and the environment with respect, because our lives depend on it. From biodiversity to air, to water quality and climate change, Stand.earth designs and implements strategies that make protecting our planet everyone's business. Its current campaigns focus on shifting corporate behavior, breaking the human addiction to fossil fuels, and developing the leadership required to catalyze long-term change.

Sunflower Alliance engages in advocacy, education, and organizing to promote the health and safety of San Francisco Bay Area communities threatened by the toxic pollution and climate-disruptive impacts of the fossil fuel industry. They are a grassroots group committed to activating broader public engagement in building an equitable, regenerative, and renewable energy-fueled economy.

The Climate Center works to rapidly reduce climate pollution at scale, starting in California. The Climate Center's strategic goal is that by 2025, California will enact policies to accelerate equitable climate action, achieving net-negative emissions and resilient communities for all by 2030, catalyzing other states, the nation and the world to take effective and equity-centered climate action.

350 Contra Costa is a home base and welcoming front door to mobilize environmental activism. It is comprised of concerned citizens taking action for a better community. They envision a world where all people equitably share clean air, water and soil in a healthy, sustainable, and post-carbon future. It is a local affiliate of 350 Bay Area**.**

II. THE PROJECT DESCRIPTION IN THE DEIR IS LEGALLY INADEQUATE[1]

An EIR must describe a proposed project with sufficient detail and accuracy to permit informed decision-making, as an inaccurate or incomplete project description renders the analysis of significant environmental impacts inherently unreliable. *See* CEQA Guidelines § 15124. "An accurate, stable and finite project description is the *sine qua non* of an informative and legally sufficient EIR." *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus*, 27 Cal.App.4th 713, 730 (1994), quoting *County of Inyo v. City of Los Angeles*, 71 Cal.App.3d 185, 193 (1977). "An accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity." *San Joaquin Raptor*, 27 Cal.App.4th at730 (citation omitted).

Accordingly, courts have found that even if an EIR is adequate in all other respects, the use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency did not proceed in a manner required by law. *Id.* When an EIR fails to disclose the "true scope" of a project because it "concealed, ignored, excluded, or simply failed to provide pertinent information" regarding the reasonably foreseeable consequences of the project, then the EIR is inadequate as a matter of law because it violated the information disclosure provisions of CEQA. *Communities for a Better Environment v. City of Richmond* (2010) 184 Cal.App.4th 70, 82-83 ("*City of Richmond*").

The Project DEIR fails to meet basic CEQA requirements for complete and accurate project description. As described in more detail below, the DEIR's cursory description failed entirely to address the actual processes and process chemistry associated with biofuel refining; and failed to address the operational duration of the Project, which is highly relevant to impacts expected to worsen over time.

A. The Project Description Failed to Disclose All Project Components

1. The DEIR Failed to Disclose Two Project Components Undertaken Separately From the Project Permitting Process

The Project as described in the DEIR fails to describe two actions already taken by Phillips 66 that are functionally part of the Project, and therefore needed to be disclosed as such. These actions both involved physical changes within the refinery, integrated with and functionally interdependent with the proposed Project operation. Both were implemented contemporaneously after the Project application (Application) was filed.

Each of these undisclosed actions expands the scope and severity of potential impacts resulting from the Project. One of these actions, the unpermitted conversion of Unit 250, is identified in the DEIR but expressly – and incorrectly – disclaimed as part of the Project. The other action, the Nustar Shore Terminals project, is not identified or evaluated in the DEIR at all. The subsections below address each of these actions.

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[1] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "Project Description and Scope."

a. The Unpermitted Conversion of Unit 250

During 2021, Phillips 66 implemented the conversion of diesel hydrotreater Unit 250 within the Rodeo Facility from petroleum distillate to soybean oil processing[2] without a Clean Air Act permit and without any public review. In the DEIR, the County disclaims any connection between Unit 250 and the Project on the dubious ground that no further changes are proposed to it:

> As explained in the Project Description, Section 3.7, Project Operation, the facility currently has the capacity to produce approximately 12,000 bpd of renewable fuels from pretreated feedstocks using Unit 250, which was previously used to process petroleum-based feedstocks. Unit 250 is not included in the Project as the Project does not propose any changes for Unit 250 and it would continue to produce 12,000 bpd of renewable fuels. Given that Unit 250 is not part of the Project, Unit 250 feedstock and production numbers are not included in this chart under the No Project Alternative.

DEIR at 5-11. But the fact that no *further* changes are proposed to Unit 250 is irrelevant 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 by all indications they are. The Project would depend on Unit 250 to maximize onsite refining of the pretreated feed output; and in turn, Unit 250 would be dependent on the Project for economical access to pretreated feed, feedstock acquisition, and Unit 250 product distribution.[3] It thus appears, based on all available information, to be an interdependent component of the Project that is essential to achieve a project objective to maximize project-supplied California biofuels.

Even more problematically, the conversion of Unit 250 earlier this year 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.[4] Phillips 66 converted the unit without seeking BAAQMD approval.[5] That investigation, and the possible misfeasance by Phillips 66, underscores the need for the DEIR to determine whether Unit 250 is functionally part of the Project and if so – which appears to be the case – evaluate it as such. The changes to Unit 250, to the extent they are part of the Project, would exacerbate its impacts, including those associated with feed acquisition, processing, and product distribution-related impacts.

Furthermore, the failure to include and disclose the Unit 250 changes 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.

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[2] PSX Q1 2021 Earnings Call.

[3] Karras, 2021c.

[4] BAAQMD, 2021.

[5] See letter to Jack Broadbent from Ann Alexander et al., July 30, 2021; Email from Damian Breen to Ann Alexander, Sept. 9, 2021.

b. NUSTAR Shore Terminals

Nustar Shore Terminals—a liquid hydrocarbons transfer and storage facility contiguous with the Refinery—and Contra Costa County have taken actions to advance the "Nustar Soybean Oil Project" contemporaneously with the Project. According to a December 2, 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. [6]

Color-coding of these pipeline sections shown on the site plan referenced by the County indicates that the new feedstock pipeline sections reach far into the Refinery; and that the vast majority of new pipeline segments by length is "Phillips 66" rather than "Nustar" pipe.[7]

There is basis to conclude, in light of these facts, that the Nustar project is an undisclosed component of the Project. The new pipelines will be supplying soybean feedstock to the Refinery, and soybean feedstock will almost certainly be used in connection with the Project (*see* Section IV). It therefore should have been evaluated in the DEIR as part of the Project; or, at the very least, the DEIR should have explicitly described why the Nustar project was not included in the impacts analysis. Instead, the DEIR neglects entirely to even mention the Nustar project.

The County, which permitted the Nustar project separately, has taken the position that it is neither a project component nor a related project: "The [Nustar Soybean Oil Project] ... is not associated with the proposed Phillips 66 Rodeo Renewed refinery conversion ,,, [and] is a stand-alone project not related to the Rodeo Renewed refinery conversion ... ."[8] Yet this response offers no support for that conclusion. The County was obligated to either present and factually support that conclusion in the DEIR – *i.e.*, with facts demonstrating that the Nustar project will not, in fact, supply feedstock to the Project – or else evaluate the Nustar project as part of the Project DEIR analysis.

c. *Terminal and Wharf Improvement Project at the Port of Los Angeles*

Phillips 66 is also taking contemporaneous action to advance the Marine Oil Terminal (MOT) and Wharf Improvement Project (MOT Project) at the Port of Los Angeles (Port of LA) Berths 148-151 in Southern California.[9] This proposed Port of LA project includes a request for

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[6] Email from Gary Kupp to Charles Davidson dated Dec. 2, 2020 and attached site map (Kupp, 2020a).

[7] Kupp, 2020a.

[8] Kupp, 2020a.

[9] City of Los Angeles Harbor Department (LAHD), Draft Initial Study/ Mitigated Negative Declaration for Berths 148-151 (Phillips 66) Marine Oil Terminal (MOT) and Wharf Improvement Project (proposed Project) at the Port of Los Angeles (Port), Nov. 2021. https://kentico.portoflosangeles.org/getmedia/d9b76ad6-9242-46e2-91b5-a7def9ac4e1f/Berths-148-151-P66-MOTEMS-Draft-IS-MND (accessed Dec 14, 2021) [hereinafter LAHD P66 IS/Neg Dec 2019]

consideration of a new 20-year entitlement (with two potential 10-year additional options) in Wilmington, an environmental justice community. Other than the Rodeo and Santa Maria refineries, Phillips 66 has only one other refinery in California—its Los Angeles refinery in Carson and Wilmington, CA. Although that refinery is never mentioned by name, the Los Angeles Refinery Emergency Response Plan is cited in the issued Draft Initial Study and Negative Declaration.[10]

In the MOT Project, Phillips 66 proposes to demolish the timber wharf at Berths 150-151, replacing it with a new concrete wharf and associated equipment, for the stated purpose of compliance with safety standards. Yet it is clear from the MOT Project documents and larger circumstances that the MOT project may have a purpose, in part, of advancing the Rodeo Renewed Project. Most notably, the draft Initial Study and Negative Declaration describes its operations at the marine terminal as "load[ing] and unload[ing] oil commodities products such…naphthas, gasoline/gasoline blend stocks, diesel and jet fuels, and distillate blend stocks, *as well as renewables and renewable feedstocks*…" (emphasis added). Furthermore, Phillips 66 is requesting up to 40 years for continued operations at Berths 148-151 despite proposing to demolish the Santa Maria site.

There is no mention of these Port of LA activities in the Project DEIR. The only mention of Los Angeles, Los Angeles County, or Southern California generally in the DEIR is with reference to the geographic location of the Santa Maria Refinery or the geographic location of potentially affected cultural resources. DEIR at 4.5-182, 4.14-422. There is one implicit reference to the Los Angeles Refinery as the "the only other Phillips 66 refinery in California besides the Santa Maria Refinery is located in the Wilmington/Carson area in Los Angeles County" as evidence to show that Phillips 66 has no other Northern California refineries. DEIR at 5-5.

However, on December 9, 2021, CARB published Phillips 66's application for a Low-Carbon Fuel Standard (LCFS) Tier 2 Pathway,[11] which highlighted a transportation link between "Southern California" and the Rodeo project being reviewed in this DEIR. The consultant report compiled for the California Air Resources Board (CARB), with reference to its third application for canola oil, traces one feedstock route that is undisclosed in the DEIR. The report describes that "The [canola oil] shipment that was received was *first sent to Southern California* for some of the oil to be off loaded and then moved north to Rodeo for unloading the remainder of the cargo. This accounts for the long transportation distance"[12] (emphasis added).

Given that the Rodeo Renewed project is Phillips 66's only biofuel conversion project proposed in California and that the DEIR details the decommissioning of the Santa Maria refinery, DEIR at 3-31, it is likely that the biofuel feedstock coming into "Southern California" are through the Port of Los Angeles. This glimpse of a potential connection between the two

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[10] LAHD P66 IS/Neg Dec 2019, pp. 107.

[11] Phillips 66 submitted a Tier 2 Pathway application for the same biofuels produced by the unpermitted and undisclosed Unit 250, described in a previous subsection. *See* (S&T)2 Consultants Inc., CARB LCFS Fuel Pathway Report Renewable Diesel Prepared for Phillips 66 Company, pp. 1-4, 7-9, Dec. 6, 2021, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0241_report.pdf (accessed Dec 14, 2021) [hereinafter CARB LCFS P66 Pathway Report 2021]

[12] CARB LCFS P66 Pathway Report 2021, pp. 5.

CEQA applications merits discussion in the DEIR and further investigation by the County. The City of Los Angeles Harbor Department (LAHD) has only granted a 30-day comment period for this Draft Initial Study and Negative Declaration. The public review period for this Phillips 66 marine terminal expansion began running on November 18, 2021 and will close on December 20, 2021. The County should immediately contact the City of Los Angeles to evaluate the relationship between the two proposed projects and CEQA reviews, and request a comment period extension for the County and the public fully evaluate the matter.

B. The Project Description Failed to Describe Aspects of the Proposed Refining Process Essential to Analyzing Project Impacts

As discussed in the sections below, the Project aspects that the DEIR fails to describe, and that are critical to understanding its impacts, are manifold. They include the following:

- Process chemistry for Hydrotreating Esters and Fatty Acids (HEFA), the biofuel refining technology proposed for the Project.
- The class, types, and differing chemistries and processing characteristics of HEFA feedstocks which can have varying upstream environmental impacts of land use changes, air quality, and safety impacts.
- The geographic sources and existing volumetric supplies of each potential feedstock, necessary to fully disclose upstream environmental impacts of land use changes.
- Hydrogen demand associated with HEFA technology, including differential hydrogen demands for production targeting HEFA diesel versus jet fuel, which affect air emission levels.
- The process chemistry of proposed hydrogen production, which could coproduce carbon dioxide, to enable processing of HEFA feedstocks
- Known differences in hydro-conversion processing between petroleum and HEFA refining, which have potential to lead to increased risk associated with HEFA refining of process upset, process safety hazard, and flaring incidents
- A Project component designed to maximize jet fuel production, which has impacts that differ from diesel production, through onsite processing of petroleum.

The DEIR also fails to disclose the anticipated and technically achievable operating duration of the Project, information that is essential to evaluate potential Project impacts which can worsen over time.

1. The DEIR Fails to Disclose Information Regarding the HEFA Biofuel Refining Process Essential to Evaluating its Impacts

The HEFA biofuel refining technology proposed to be used for the Project has important capabilities, limitations, and risks that distinguish it from other biofuel technologies. These differences result in environmental impacts associated with HEFA technology that are unique or uniquely severe as compared with other biofuel technologies.

The DEIR, however, describes none of this. In its entire 400-plus pages, it does not once even mention or reference HEFA, or in any way describe what it is and how it works. This is a major deficiency, and inadequate disclosure that undercuts the integrity of the entire DEIR analysis, for reasons described throughout this Comment with respect to the risks and impacts that attend HEFA production.

The following subsections describe the aspects of the HEFA process that needed to be included in a description of the Project but were not.

a. HEFA as the Proposed Type of Processing

As noted above, the DEIR never once mentions that HEFA is the technology the Project would employ. It can be discerned nonetheless that HEFA is, in fact, the proposed technology, based on the Project's sole reliance upon repurposed refinery hydrotreaters and hydrocrackers for feed conversion to fuels, and upon repurposed refinery hydrogen plants to produce and supply hydrogen for that hydro-conversion processing. This is confirmed by independent expert review of the Project.[13] [14] [15]

But the fact that technical experts (such as Commenters') can read between the lines and discern that HEFA is the proposed technology does not satisfy CEQA's requirement that the County directly disclose this information to the public. Such disclosure was particularly important here given the wide range of existing biofuel technologies and environmentally significant differences between them, and the significant environmental impacts that attend HEFA production. In a revised DEIR, the County should disclose, explain, and evaluate the specific impacts of HEFA production.

b. Capabilities and Limitations of HEFA

HEFA processing technology differs from most or all other commercially available biofuel technologies in many ways linked to environmental impacts, in ways that must be known in order to evaluate Project impacts.[16] [17] [18] First, HEFA biofuels can be produced by repurposing

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[13] Karras, G, *Changing Hydrocarbons Midstream*; technical report and accompanying supporting material appendix for Natural Resources Defense Council, San Francisco, CA, June 2021 (Karras, 2021a).

[14] Karras, G, *Unsustainable Aviation Fuel;* technical report for Natural Resources Defense Council, San Francisco, CA, August 2021 (Karras, 2021b).

[15] Karras, G, *Technical Report in Support of Comments Concerning Rodeo Renewed Project*; technical report prepared for Natural Resources Defense Council, San Francisco, CA, December 2021 (Karras, 2021c).

[16] Karras, 2021a and 2021b.

[17] Karras, 2021a.

[18] Karras, 2021b.

otherwise stranded petroleum refining assets, thereby potentially extending the operable duration and resultant local impacts of large combustion fuel refineries concentrated in disparately toxic low income Black and Brown communities. Second, HEFA diesel can be blended with petroleum diesel in pipelines, petroleum storage tanks, and internal combustion vehicles in any amount, thereby raising the potential for competition with or interference with California climate goals for the development of zero-emission vehicles infrastructure for climate stabilization. Third, HEFA technology has inherent limitations that affect its potential as a sustainable substitute for petroleum diesel, jet fuel, or both - including its low yield on feedstock, high hydrogen demand, and limited feedstock supply. The DEIR fails to disclose or describe any these basic differences between HEFA and other biofuels (having failed to even mention HEFA at all), thereby obscuring unique or uniquely pronounced environmental consequences of the type of biofuel project proposed.

c. *HEFA process chemistry*

HEFA process chemistry reacts lipidic (oily) vegetable oils and animal fats with hydrogen over a catalyst at high temperature and very high pressure to produce and alter the chemical structure of deoxygenated hydrocarbons. Although this is done in repurposed refinery equipment, this process chemistry is radically different from petroleum processing in respects that lead directly to potential environmental impacts of the Project.[19] Moreover, site-specific differences in process design conditions[20]—which have been reported in other CEQA reviews for oil refining projects[21]—can affect the severity of impacts significantly. The DEIR fails to disclose or describe this basic information.

d. *Differing hydrogen demand associated with different feedstocks and product slates*

Known environmental emissions and hazards of HEFA processing are related in part to the amount of hydrogen demand per barrel of feed converted to biofuel, which varies significantly among HEFA feedstocks and product production targets.[22] The DEIR does not disclose this data. Moreover, to a significant degree, process hydrogen demand and thus resultant impacts may vary depending on plant and Project-specific design specifications, data the DEIR likewise fails to disclose or describe.

e. *Process chemistry of proposed hydrogen production*

This deficiency in the DEIR project description fails to inform the public of known climate impacts the proposed Project would cause and fails to disclose data necessary to adequate review of Project impacts. First, the DEIR fails to specifically disclose that the type of hydrogen production proposed for this "renewable" fuels Project would use fossil gas hydrogen

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[19] *Id.*

[20] In addition to process-specific operating temperatures, pressures, and engineered process controls such as quench and depressurization systems, examples include process unit-specific input, internal recycle rates, hydrogen consumption rates, and even how those operating conditions interact across refining processes to affect overall hydrogen demand when processing feedstocks of various qualities.

[21] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model.

[22] *Id.*

production, which, because of its production chemistry, can emit roughly ten tons of carbon dioxide per ton of hydrogen produced.[23] The DEIR further fails to describe the high *and* variable carbon intensity of fossil gas hydrogen technology among specific plants and refineries;[24] and the Project-specific hydrogen production design data necessary for impact estimation.

f. Differences between HEFA and petroleum refining that increase risk of process upset, process safety hazard, and flaring incidents

There is a risk of upsets, fires, explosions, and flaring (Section V) linked to specific process hazards that switching from petroleum to HEFA processing has known potential intensify.[25] The DEIR fails to disclose the aspects of the HEFA process creating these hazards, and fails to describe the known differences between HEFA and crude refining that could worsen these impacts.

g. Process upset, process safety hazard, and flaring incident records at the Refinery

The risk of explosion, fire, and flaring impact of the proposed HEFA refining is associated with specific design and operating specifications of the Refinery units proposed for conversion. These specifications, and the attendant risk, can be estimated using available data concerning past incidents involving the same units.[26] [27] The DEIR fails to disclose of address this incident data.

The failure to describe anything at all about the proposed new technology makes a meaningful evaluation of its impacts impossible. Moreover, failing to name and describe HEFA technology eliminated the opportunity for the County to assess whether an alternative biofuel production technology (e.g., Fischer-Tropsch synthesis) might result in different impacts. This analytical limitation was compounded by the DEIR's overly narrow description of the Project's purpose described in Section VIII, which accepted at face value Marathon's commercial desire to repurpose its stranded asset to the greatest extent possible, an assumption that biased the DEIR against consideration of alternative technologies.

2. <u>The DEIR Fails to Disclose Adequate Information Concerning HEFA Feedstocks</u>

HEFA feedstock is limited to lipids (triacylglycerols and fatty acids freed from them) produced as primary or secondary agricultural products, but there are many different oils and fat in this class of feedstocks, and many environmentally significant differences between them in terms of chemistry and process characteristics.[28] As discussed in Sections IV, VI, and VII, choice of feedstock has a major effect on the magnitude and potential significance of multiple impacts, from upstream land use impacts to process safety to air emissions.

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[23] Karras, 2021a.

[24] Sun et al. 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Reforming Facilities. *Environ. Sci. Technol.* 53: 71.3–7113. DOI: 10.1021/acs.est.8b06197

[25] Karras, 2021a,

[26] *Id.*

[27] BAAQMD Causal Reports for Significant Flaring. BAAQMD Regulations, §12-12-406 of Regulation 12, Rule 12; Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd/gov/rules-and-compliance/current-rules

[28] *Id.*

The DEIR, however, declines to identify proposed Project feedstocks with any specificity, stating only that anticipated feedstocks include, without limitation, used cooking oil (UCO), fats, oils, and grease (FOG), tallow, "inedible" corn oil (presumably meaning distillers corn oil, or DCO), canola oil, soybean oil (SBO), "other vegetable-based oils," and/or "emerging and other next-generation feedstocks." DEIR at 3-25-27. The document does not disclose or analyze the percentage of each feedstock anticipated to be used, stating that it is not feasible to predict source and types of feedstocks because feedstock choice will be "influenced by business considerations and market conditions - described to include commodity prices and fungibility. *Id.* at 3-27.

This description is entirely inadequate to inform the public regarding the nature and impacts of the Project – regardless of whether or not it is possible to specify an exact quantity of each feedstock that will be used into the future. Even the absence of such precise information, the County was obligated to use available information to estimate the likelihood of any given feedstock or combination of feedstocks will be used. Section IV details some of that information on upstream environmental impacts of land use changes, presenting multiple sources of data concerning availability and current use patterns of known feedstocks. That information is sufficient to develop at least a reasonable prediction of the likely mix, or range of potential mixes.

The DEIR should have developed scenarios (including a reasonable worst case scenario – *see* Section IV) for likely feedstock mixes. It should also have specified likely sources for anticipated feedstocks, necessary to facilitate analysis of the upstream environmental impacts of land use changes described in Section IV. Then, as described in that section, the DEIR should have evaluated capping the use of particular feedstocks as a mitigation measure.

3. The DEIR Fails to Disclose a Project Component Designed to Debottleneck Hydrogen-limited Onsite Refining Capacity

Phillips 66 added a Project component after the public scoping process that is not disclosed in the DEIR, but may result in significant impacts. This component would relieve a bottleneck in hydrogen-limited biofuel processing at the Refinery by repurposing additional existing refinery equipment to co-produce hydrogen as a byproduct of processing gasoline feedstocks derived from semi-refined petroleum imported to Rodeo. Although the DEIR identifies the physical changes integrated into the Project post-scoping, it does not identify the purpose of these changes as de-bottlenecking, and hence fails to disclose and evaluate the environmental impacts of such debottlenecking, which will result in additional onsite processing of petroleum and biomass.

As discussed in the previous subsection, the DEIR does not address the process role of hydrogen in the HEFA process at all; and hence does not evaluate HEFA process demand. As such, it fails to identify an existing hydrogen bottleneck at the Refinery which, if removed, would enable processing the additional pretreated feedstock the revised Project would produce. The County could (if it had focused on the HEFA process at all) have readily identified this bottleneck by comparing hydrogen production capacity and process hydrogen demand data for the disclosed Project components.[29] 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 biofuel production. Targeting HEFA jet fuel, a more hydrogen-intensive refining mode,[30] the hydrogen bottleneck could limit onsite biofuel refining capacity to only about 60% to 70% of pretreated feed capacity.[31]

The debottlenecking can be discerned 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.[32] Refinery crude distillation units would be shuttered upon full Project implementation,[33] 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. Phillips 66 recently stated in other contexts that it is shifting the specialty coke production from its petroleum refining to produce graphite for batteries[34] and planning to use the Rodeo coking unit for that purpose.[35] The coking would co-produce light oils its reformers would then convert to gasoline blend stocks.

The debottlenecking element is that the light oil reforming would in turn co-produce hydrogen, thereby alleviating the jet biofuel production bottleneck described above. The DEIR nowhere identifies this important impact of the retained permits.

This undisclosed hydrogen debottlenecking action and the disclosed Project components would be interdependent components of the Project. The hydrogen debottleneck component depends on 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%.[36] 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 is highly incentivized to debottleneck its biorefinery; has asserted informal plans *and* formal Project objectives[37] consistent with that result; and crucially, has changed its Project to include the specific equipment which would be used to debottleneck the

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[29] Karras, 2021b.

[30] *Id.*

[31] Karras, 2021c.

[32] BAAQMD Application, 2021. *Compare* also Phillips 66 initial Project Description; DEIR pp. 3-28, 3-29.

[33] DEIR pp. 3-28, 3-29.

[34] Phillips 66 3Q 2021 Earnings Conference Call; 29 Oct 2021, 12 p.m. ET.

[35] Personal communication between Charles Davidson, Rodeo Citizens Association, and Greg Karras, Community Energy reSource. 28 October 2021.

[36] Pearlson et al., 2013.

[37] DEIR p. 3-22 (objectives to maximize production of renewable fuels and reuse existing equipment to do so).

Project's capacity. In the absence of a binding assurance that petroleum products processing will cease, the DEIR should have identified this hydrogen debottleneck as a component of the Project, and its potentially significant environmental impacts evaluated and mitigated to the extent possible.

C. The Project Description Failed to Disclose the Operational Duration of the Project, Essential to Describing Impacts that Worsen Over Time

Essential to evaluating environmental impacts of the Project is knowing the period over which the impacts could occur, and could worsen. Thus, the operational duration of the Project is highly relevant to evaluating impacts that may accumulate or otherwise worsen over time.

However, the DEIR fails to disclose the anticipated and technically achievable operational duration of the Project. The necessary data and information could have been obtained from various sources. First, the County should have taken into consideration the declining place of combustion fuel as California moves toward its climate goals, and the County fulfils its own "Diesel Free in '33" pledge (Section VI). Additionally, the County could have requested operational duration data from Phillips 66 as necessary supporting data for its permit application. Such data could also have been accessed from publicly reported sources. For example, process unit-specific operational duration data from Bay Area refineries, including data for some of the same types of process units to be repurposed by the Project, have been compiled, analyzed and reported publicly by Communities for a Better Environment.[38]

III. THE DEIR IDENTIFIES AN IMPROPER BASELINE FOR THE PROJECT[39]

The DEIR commits a major error in using an operating crude oil refinery as a baseline for determining impact significance. All available information indicates that Phillips 66 is in the process of phasing out its Santa Maria refinery, the only available source of petroleum feedstock for the Refinery, regardless of whether the County grants a permit for the Project. The end of petroleum refining at the Refinery is thus inevitable in the near term, with or without the Project. It is hence deeply misleading that the DEIR identifies previous years in which the Refinery was fully operational as a Project baseline. Failure to inform the public of the Refinery's existing trajectory toward ending petroleum processing creates the incorrect impression that the Project reflects a reduction in impacts from an artificially inflated baseline.

A. CEQA Requires Use of an Accurate Baseline

The purpose of a description of baseline conditions is "to give the public and decision makers the most accurate and understandable picture practically possible of the project's likely near-term and long-term impacts." CEQA Guidelines at 15125(a). The baseline should generally "describe physical environmental conditions as they exist at the time the notice of preparation is published." CEQA Guidelines § 15125. But where "use of existing conditions

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[38] Karras, 2020. Decommissioning California Refineries

[39] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "The DEIR Obscures the Significance of Project Impacts by Asserting an Inflated Alternative Baseline Without Factual Support."

would be either misleading or without informative value to decision makers and the public," use of a baseline reflecting projected future conditions is appropriate. *Id.* § 15125(a)(1) and (2).

"An approach using hypothetical allowable conditions as the baseline results in 'illusory' comparisons that 'can only mislead the public as to the reality of the impacts and subvert full consideration of the actual environmental impacts,' a result at direct odds with CEQA's intent." *Communities for a Better Environment v. South Coast Air Quality Management District*, (2010), 48 Cal4th 310, 322. Accordingly, the existence of permits allowing a certain level of operation is not appropriately determinative of baseline "physical environmental conditions." *Id.* at 320-21 ("A long line of Court of Appeal decisions holds, in similar terms, that the impacts of a proposed project are ordinarily to be compared to the actual environmental conditions existing at the time of CEQA analysis, rather than to allowable conditions defined by a plan or regulatory framework.").

Thus, the DEIR analysis concerning baseline identification is legally deficient. The issue is not whether the Refinery's emissions fluctuated over time during past years. DEIR at 3-36, citing CEQA Guidelines § 15125(a)(1). It is that the Refinery's current existing conditions reflect a winding down of its crude oil processing operations; such that its inevitable near-term future conditions involve not processing crude oil at all.

B. Available Evidence Makes Clear that Phillips 66 is Winding Down Operations at the Refinery Regardless of Whether the Project Moves Forward

The DEIR selects 2019 as the baseline year for evaluating Project impacts. DEIR at 3-37 – 38. However, this choice of baseline reflects neither current nor near-term future reality. In fact, the steadily declining availability of crude feedstock supply to the Refinery makes clear that it is simply not possible that 2019 production levels will continue indefinitely.

As discussed in detail in the sections below, available evidence leads to the conclusion that the Phillips 66 Santa Maria refinery (Santa Maria facility) and Refinery which functionally depends on it are on a trajectory to reduce or cease their crude processing operations in the relatively near term even if the County does not approve the Project, due to supply limitations and the increasingly poor economics of crude oil refining. Thus, the appropriate baseline for assessing Project impacts is not indefinitely continued crude oil refining, but rather a slowdown or shutdown of one or both facilities. This would mean that the Project would not achieve all - or possibly any – of the claimed emissions reductions set forth in the Project application; and might, in fact, increase emissions significantly over the baseline.

The near-term inevitability of the Refinery's curtailment or closure is evident in the history of the Refinery's operations, and available public data, as discussed in the sections below. Indeed, it is evident even in the Project application (Application), which assumes closure of the Phillips 66 Santa Maria facility – a current source of Rodeo feedstock via pipeline. It asserts that Phillips 66 needs authorization to increase crude and gas oil imports over its Rodeo marine terminal by up to 73,818 barrels per day[40] (b/d) until its biofuel conversion is built and

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[40] The current marine terminal input limit is 51,182 b/d, and Phillips 66 proposes to increase that limit up to 125,000 b/d. Notice of Preparation at 3.

fully online,[41] "to accommodate the idling and decommissioning of the Santa Maria facility in San Luis Obispo County."[42] Yet the Application does not specifically identify closure of the Santa Maria refinery as a component of the Project – it simply assumes it as a background fact.[43]

The following sections address in detail why the DEIR conclusions re an appropriate baseline are based in inadequate informational disclosure, and unsupported by substantial evidence.

1. Inherent Infrastructure Constraints Limit Crude Feedstock Availability to the SF Complex

The DEIR expressly acknowledges that continued crude refining would be infeasible at the Refinery if and when the Refinery loses access to crude and semi-refined crude from the Santa Maria facility and pipeline system. DEIR at 5-3. As discussed below, the Santa Maria facility is essential to the Refinery's ability to obtain refining feedstock other than crude brought in over the wharf.

It is thus fatal to the DEIR's baseline analysis that the DEIR fails to disclose factors that are already leading to the inevitable near-term closure of the Santa Maria facility, regardless of the Project. Specifically, the DEIR fails to disclose or evaluate (and also erroneously describes) the functional interdependence of the Refinery, Santa Maria facility, and pipeline system as essential components of the San Francisco Refining Complex (SF Complex); the unique geography of these SF Complex components; and the resultant unique limitations in currently accessible crude feedstock for the Santa Maria facility and hence for the Refinery. These unacknowledged limitations on the Refinery's ability to operate exist independently of Project-related decisionmaking. And as discussed below, they will make continued crude processing at the Refinery at historic levels impossible – belying the baseline identified in the DEIR.

Map 1 illustrates the unique geographic distribution of SF Complex refining and pipeline components, in relation to the landlocked crude resources the SF Complex was uniquely designed to access for feedstock - including pipeline-linked Outer Continental Shelf (OCS), Central Coast onshore, and San Joaquin Valley crude resources.[44] Crucially, the Santa Maria facility, marked "B" in Map 1, has no seaport access to import foreign and Alaskan crude via marine vessels,[45] which refiners statewide have come to rely upon for the majority of statewide refinery feedstock.[46]

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[41] The increase would be from the current marine terminal input limit of 51,182 barrels per day (b/d) limit now to 125,000 b/d.

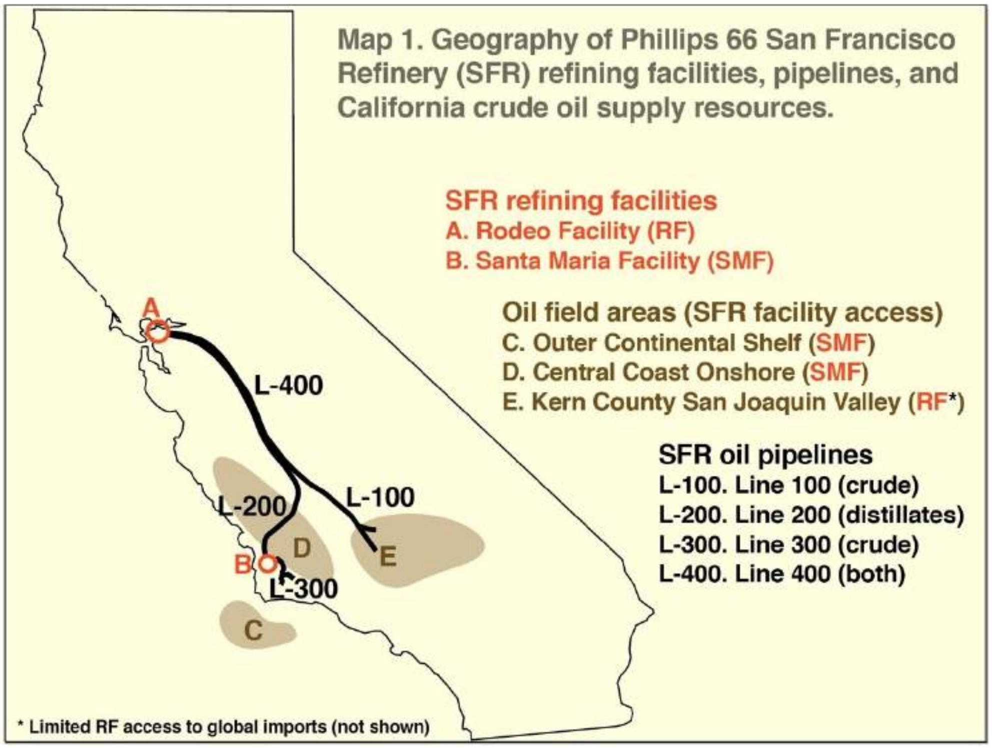
[42] Application at 12.

[43] *Id.* at 11-12 (listing Project components).

[44] Map 1 is only approximately to scale, consistent with facility and pipeline maps in the DEIR, and based also upon state and federal oilfield location and accessibility data, as documented in Karras, 2021c.

[45] 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.

[46] *Crude Oil Sources for California Refineries;* California Energy Commission: Sacramento, CA. (CEC, 2021a).



As illustrated, the sources of crude for the Santa Maria facility are very limited. There is only one local pipeline supplying crude to the Santa Maria facility, limiting its ability to access crude from outside the local area.[47] The Santa Maria facility has access to several local onshore oilfields via truck transport to a local pipeline pump station, but such transport is sufficient to supply only about half of the facility's capacity.[48] As of 2014, OCS oilfields connected to the Santa Maria facility's single crude input pipeline via pipelines from Santa Barbara County ("C" in Map 1) supplied up to 85% of the Santa Maria facility crude input.[49] By contrast, the largest still-producing onshore oilfield that historically supplied the Santa Maria facility, the San Ardo oilfield in Monterey County (part of "D" in Map 1) supplied only 5–10% of its crude as of 2014.[50] The DEIR does not disclose this crude supply limitation of the Santa Maria facility – and hence the Refinery - or evaluate the Refinery's resultant reliance on the portion of OCS crude which the Santa Maria facility can access via pipelines and historically smaller onshore crude resources in San Luis Obispo County and parts of Santa Barbara and Monterey counties ("D" in Map 1).[51]

The DEIR commits a clear error in its setting description that further obscures the Santa Maria facility's very limited access to crude oil supply – indicating access to resources that that facility does not, in fact, have. Pipeline system Line 100 ("L-100" in Map 1), which runs from Kern County oilfields in the San Joaquin Valley ("E" in Map 1), does not connect at all to the Santa Maria facility. It runs north to the junction with Line 200 from the Santa Maria facility

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[47] SLOC, 2014.
[48] SLOC, 2014.
[49] SLOC, 2014.
[50] SLOC, 2014.
[51] Karras, 2021c.

and Line 400 to the Refinery, where the Kern crude and partially refined oil output from the Santa Maria refinery both flow north through Line 400 to the Refinery.[52] The DEIR, however, erroneously describes Line 100 as directly supplying the Santa Maria refinery: "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 Santa Maria refinery lacks access to San Joaquin oilfields—the largest remaining regional crude resource in California.[53] [54]

The Refinery likewise lacks access to the Kern County oil fields if the Santa Maria facility closes, despite the fact that Line 400 (connected to the Kern County fields via Line 100) runs directly to it. The DEIR correctly states that the entire pipeline system would shutter in place when the Santa Maria facility closes, providing that conclusion as a reason for a "transitional" increase in permitted crude inputs to the Refinery through its marine terminal. DEIR at 3-32; *see Id.* at 5-3.[55] Although the DEIR does not explain this, the reason the pipeline system would not continue to function after the closure of the Santa Maria facility is that lines 100 and 400 cannot physically function effectively without input from the Santa Maria facility. This is because the naphtha and pressure distillate from the Santa Maria facility thins the viscous (thick like molasses) Kern County San Joaquin Valley Heavy crude ("E" in Map 1), thus enabling it to move through Line 400 to the RF.[56]

Thus, in baseline conditions – without the "transitional" marine terminal throughput increase – the Refinery's only potential source of crude is the limited volume of crude it can bring in over the wharf at currently permitted volumes. Those permitted volumes are enough to supply only 47 percent of the Refinery's throughput capacity, as explained in the DEIR analysis of the alternative of shutting down the Santa Maria facility but keeping the Refinery open. DEIR at 5-3. Processing only these limited volumes brought in over the wharf over current limits would result in the refinery operating at a far lower throughput rate than described in the DEIR's baseline scenario. . The DEIR functionally already recognizes that this scenario is not realistic, having acknowledged that continued crude refining would be infeasible at the Refinery if and when the Refinery loses access to crude and semi-refined crude from the Santa Maria facility and pipeline system. DEIR at 5-3.

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[52] Karras, 2021c. Careful review of DEIR Figure 3-5 confirms this accurate description of pipeline flows, once the reader knows that crude does not flow to the SMF through Line 200. However, the erroneous assertion in the text on page 3-21 of the DEIR is misleading on that point because it could only make sense by assuming the opposite.

[53] Karras, 2021c.

[54] This error in the DEIR further compounds its failure to disclose the Santa Maria facility's – and hence the Refinery's – very limited access to crude, in the absence of seaport access. Gasoline, diesel and jet fuel production from the crude accessed and partially refined into naphtha and gas oil ("pressure distillate") at the Santa Maria facility, then sent through lines 200 and 400, relies entirely on further processing at the Refinery ("A" in Map 1). This too, is not described in the DEIR.

[55] Karras, 2021c.

[56] Karras, 2021c.

2. The Permitting History of the Refinery Evidences Declining Crude Feedstock Availability

Having failed to accurately describe the infrastructure constraints limiting the Refinery's access to crude oil, the DEIR further fails to disclose information indicating that even this limited supply is diminishing – hence, by the company's own admission, foreclosing the Refinery's ability to continue processing crude at historic levels in the absence of the Project. Had they been included in the DEIR, would have contravened the County's conclusion that these historic levels represent an appropriate baseline (and no project alternative, as discussed in Section VIII).

Specifically, the DEIR fails to disclose that prior to proposing this Project, Phillips 66 warned that lack of access to crude oil, with such access being circumscribed as described in the subsection above, could lead to processing rate curtailments at the Refinery. On September 6, 2019 Carl Perkins, then the Phillips 66 Rodeo refinery manager, wrote Jack Broadbent, the Executive Director of the Bay Area Air Quality Management District, offering "concessions" in return for advancing a project proposed by the refiner to increase crude and gas oil imports to the Refinery via marine vessels.[57] 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."[58] Perkins further stated that the refiner "seeks to ensure 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 [Rodeo] refinery ... ."[59]

Underpinning these concerns with continued crude oil availability at the Refinery is the fact that the economics of obtaining feedstock from the Santa Maria facility are becoming less optimal; that production at the Santa Maria facility has been sharply declining.; and that these factors led to a decision to close the Santa Maria facility independent of the Project. 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 Refinery's 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 Santa Maria facility rail spur extension.[60] In its review of that proposed rail spur, San Luis Obispo County described the limited Santa Maria facility access to crude and how that limited its access to competitively priced crude, then previewed, during 2014, the 2019 warning by Phillips 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 ... In the long-term, the ... remaining life of the refinery is dependent on crude oil supplies, prices and overall economics."[61] The DEIR does not disclose those findings. And in fact, permits for that rail spur extension were denied and it was never built. The DEIR fails to evaluate whether the "long-term" need to replace declining sources of crude for the Refinery identified in 2014 is now an acute short-term need.

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[57] Perkins, 2019.

[58] Perkins, 2019.

[59] Perkins, 2019.

[60] SLOC, 2014.

[61] SLOC, 2014.

Recent events, undisclosed in the DEIR, indicate the need is, indeed, acute at the Santa Maria facility on which the Refinery depends. By 2017, ExxonMobil proposed to temporarily truck crude to the Santa Maria facility, a proposal the Santa County Planning Commission later voted to deny.[62] Phillips 66 abandoned its proposed Santa Maria facility pipeline replacement project in August 2020.[63] This fact strongly indicates that the company's plan to decommission the Santa Maria facility was developed independently from the Project, and was already underway before Phillips 66 filed its Application with the County.

Overall, it is important to recognize that no other California refinery is built to access isolated crude resources with landlocked front-end refining hundreds of pipeline miles from its back-end refining. And no other faces the crisis this built-in reliance on geographically limited and finite resources has wrought. The DEIR's failure to recognize and address these unique circumstances faced by the Refinery is a fatal flaw.

3. Available Crude Supply Data Demonstrate Declining Feedstock Availability at the Santa Maria Facility

The County could and should have disclosed and considered, in setting the baseline, abundant crude oil production data indicating that available supply to the Santa Maria facility – and hence to the Refinery – is being steadily choked off as the California production on which it is dependent declines. Failure to do so undercuts the validity of the baseline determination, and renders it unsupported by substantial evidence. Given the decline trajectory, there is no sound basis to assume that future production levels at the Santa Maria facility and the Refinery will continue to match 2019 levels. Indeed, the decline points to and supports an inference that the Santa Maria facility is already headed for closure.

In 2014 San Luis Obispo County conducted the type of crude access limitation review for the Santa Maria facility that found steeply declining crude feedstock availability. This review was referenced in the Scoping Comments but ignored by the County. It should not have been, because it is pertinent to the question of baseline and clearly undercuts the DEIR's conclusion regarding it. It should hence have been disclosed and addressed in the DEIR – especially given that (as discussed below and above), constraints have only gotten more severe in the intervening years. San Luis Obispo County found that as of 2014, the facility's continuing crude supply was already in doubt:

> Having only one pipeline system available for delivering crude oil to the refinery limits the [Santa Maria facility] refinery's ability to obtain crude oil from sources outside the local area. ... In the long-term, the need [for the Santa Maria facility to access new sources of crude] could be driven by declines in local production of crude oil that can be delivered by pipeline. Production from offshore ... (OCS crude) has been in decline for a number of years. Oil production in Santa Barbara County (both onshore and offshore) peaked at about 188,000 barrels in 1995 ...

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[62] 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.

[63] 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

> and currently production is around 61,000 barrels per day for both onshore and offshore oil fields ... . [T]he success and amount of additional production from [new] projects is currently speculative.[64]

Currently available data confirm that feedstock availability at the Santa Maria facility has continued to deteriorate through the present time. The U.S. Bureau of Ocean Energy Management (BOEM) reports production data for OCS oilfields that the Santa Maria facility historically and currently can access via pipelines.[65] [66] These data, which the DEIR does not disclose or discuss, are summarized in Chart 1.

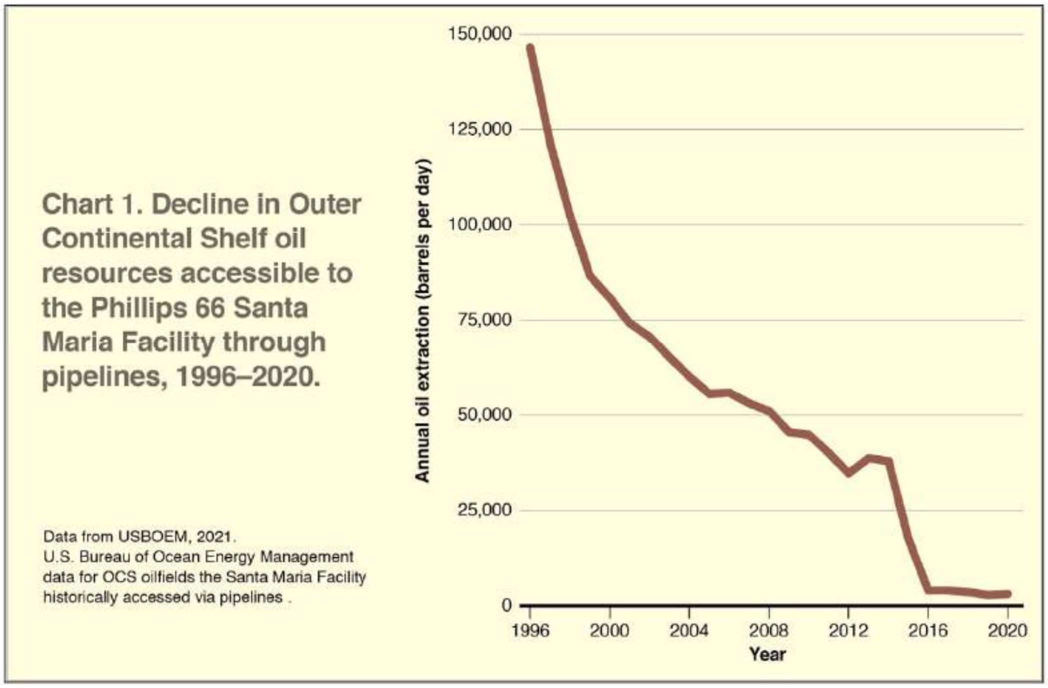

Chart 1. Decline in Outer Continental Shelf oil resources accessible to the Phillips 66 Santa Maria Facility through pipelines, 1996–2020.

Data from USBOEM, 2021.
U.S. Bureau of Ocean Energy Management data for OCS oilfields the Santa Maria Facility historically accessed via pipelines .

The BOEM data illustrated in Chart 1 indicate that crude production from OCS oilfields that the Santa Maria facility has historically been able to access continued in steep long-term decline after the 2014 San Luis Obispo analysis. From an annual average of approximately 146,000 barrels per day (b/d) in 1996, OCS oil production from these fields,[67] collectively, fell by 98% to approximately 3,000 b/d in 2020.[68] Had the DEIR disclosed these data, the County could and should have found that the historically dominant OCS source of crude refined by the Santa Maria facility is in steep terminal decline; and hence that a baseline grounded in assumptions of historic production levels is unsupportable.

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[64] SLOC, 2014.

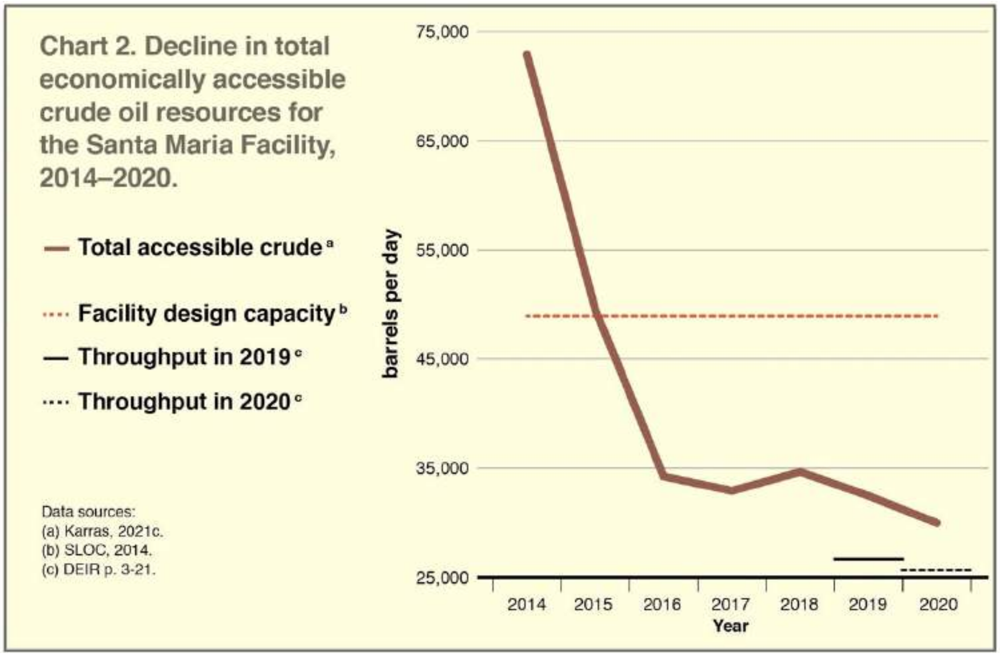
[65] USBOEM, 2021a. U.S. Bureau of Ocean Energy Management. *Pacific Production;* data tables for the Pacific OCS Region, 1996–2021. https://www.data.boem.gov/Main/PacificProduction.aspx#ascii

[66] USBOEM, 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.

[67] These OCS oilfields that the SMF could historically or currently access via pipelines are the Point Pedernales, Point Arguello, Hondo, Pescado, and Sacate fields. *See* USBOEM, 2021b.

[68] USBOEM, 2021a.

State data, also not disclosed or addressed in the DEIR, further support a conclusion that available feedstock for the Santa Maria facility (and hence the Refinery) is steadily and precipitously declining. The California Air Resources Board (CARB) and the Geologic Energy Management Division (CalGEM, formerly DOGGR) both have collected data concerning the total annual amounts of crude actually refined from each OCS and State offshore and onshore oilfield.[69] The County could have, but did not, report and evaluate changes in the annual volumes of crude actually refined in California which were derived from OCS and onshore oilfields that the SMF can access.[70] Chart 2, based on the CalGEM/DOGGR data, confirms the declining availability of crude feedstock supply to the Santa Maria facility.[71]



The falling brown curve illustrates the rapid decline in total crude accessible to the Santa Maria facility that was refined statewide since 2014. Most importantly, its fall below the dashed red line indicates this dwindling crude supply could no longer support Santa Maria facility operation at or even near capacity. From approximately 73,000 b/d in 2014, total refining of Central Coast onshore, offshore, and OCS crude accessible to the Santa Maria facility via truck and pipeline fell by 59%, to approximately 30,000 b/d in 2020.[72] In 2019, before COVID-19, the Santa Maria

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[69] 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

[70] DOGGR, 2017. *2017 Report of California Oil and Gas Production Statistics;* California Department of Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA.

[71] For example, based on evidence described in sections B.1.1 and B.1.2 herein, Chart 2 includes all onshore and State offshore fields identified by DOGGR (2017) in District 3, and OCS oilfields included in Chart 1 as noted above, and optimistically assumes that no other California refiner competes for access to their production.

[72] Karras, 2021c.

facility was operating at only 26,700 b/d,[73] 45% below its 48,950 b/d capacity.[74] In 2020, as accessible crude fell by roughly another 2,000 b/d,[75] the SMF cut rate by another 1,000 b/d to 25,700 b/d,[76] fully 47% below its design capacity.[77]

These data demonstrate that the *currently* accessible crude supply does not allow operation at historic rates—the baseline condition conclusion in the DEIR—and strongly suggest that further dwindling access to crude would further curtail, then shutter, the crude refinery.

The County should have disclosed and evaluated all of this data, but it did not. It should additionally have required Phillips 66 to disclose relevant correlative data – *i.e.,* to provide volumes of each crude refined at each facility. The County's failure to do any of that obscures the plain falsity of its conclusion that a refinery with steadily less access to crude will continue to refine at current levels indefinitely (DEIR at 3-37). The County has thus failed to inform the public that a set of conditions that the DEIR plainly states would end crude refining at the Refinery (DEIR at 5-3) are imminently about to materialize.

4. Production Declines in the SF Complex Reflect Larger National Trends

The likelihood that production levels will continue to decline in the SF Complex is underscored by current national trends in refinery economics. Both the Santa Mara facility and the Refinery are impacted by the overall increasingly poor profit margins of crude oil refining, which has led to the closure, or conversion to biofuels production, of numerous refineries in California and throughout the world. The COVID pandemic caused short-term volatility; but refinery profits across the nation have been declining since before the pandemic. Refineries are closing or converting to biofuel production in the United States and throughout the world, and there is significant doubt whether the economics of refining will improve post-pandemic. The International Energy Agency (IEA) reported in November 2020 that roughly a dozen refinery closures had been announced in the previous few months, with the bulk of the capacity closures – over 1 million b/d – happening in the United States. IEA stated in its monthly report, "There were capacity shutdowns planned for 2020-2021 prior to COVID-19, but the bulk of the new announcements reflect pessimism about refining economics in a world suffering from temporary demand collapse and structural refining overcapacity."

Structural factors that underly this trend, predating but accelerated by COVID-19, are especially pronounced in the U.S. at West Coast refineries. Growth reversed years ago in both the crude supply and the market demand that California refineries were first built to tap. Refiners statewide reacted by increasing production through increasing reliance on oil imports and export fuels markets. The sustainability problem with that path-dependent reaction was

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[73] DEIR p. 3-21.

[74] SLOC, 2014.

[75] Karras, 2021c.

[76] DEIR p. 3-21.

[77] This very low SMF production rate in 2019 would have reduced SMF output to the RF and thus capacity to thin and enable the movement of viscous San Joaquin Valley crude through Line 400 to the RF. Among other things, that reduction in RF pipeline receipts during 2019 might help to explain the anomalously high RF marine vessel traffic in 2019 reported by the DEIR.

further revealed by COVID-19. From March 20, 2020, through January 15, 2021, fully one-fourth of statewide refining production became unproductive assets as a side effect of the pandemic, which paused personal travel. Perhaps most dispositively, even during the recent temporary surge in statewide and West Coast demand for petroleum fuels, up to 305,000 barrels per calendar day of statewide refining capacity—far more than the total capacity of this Phillips refinery—remained idle.[78] Phillips 66 faces this statewide overcapacity problem, along with the rapid terminal decline of site-specific crude resources that its refining facilities were built for and remain uniquely dependent upon.

5. Conclusion Regarding the DEIR Baseline Analysis.

The DEIR acknowledges both that crude refining at Rodeo would be infeasible without the Santa Maria facility and pipeline connecting it to the Refinery (DEIR at 5-3), and that "throughput at the Santa Maria Site has declined over time .." (p. 5-12). However, it fails to disclose the key facts driving the future of the Santa Maria facility and the Refinery described above. It then fails to draw the necessary conclusion from those facts, which is that Refinery production will be increasingly curtailed under status quo conditions; and to apply that conclusion to its selection of a baseline. The DEIR's passing statement that "declining production is not equivalent to closure" (DEIR 5-12) is meaningless and uninformative. The question is not whether those two things are "equivalent"; it is whether declining production undercuts the DEIR's assumption that production will continue at historic levels; and whether the decline signifies a likelihood of near-term closure that should have been disclosed and evaluated as part of determining an accurate baseline (as well as no project alternative).

An accurate baseline would be based on the reality that refining will not and cannot continue at 2019 levels, or anything close to them. The DEIR must be revised and recirculated with full information addressing this reality.

IV. THE DEIR FAILED TO CONSIDER THE UPSTREAM ENVIRONMENTAL IMPACTS OF FEEDSTOCKS

As the largest biofuel refinery in the world, the Project would by definition consume unprecedented volumes of feedstock – inevitably much of it consisting of agricultural food products such as soybean oil. Both the environmental analysis for the California 2017 Scoping Plan and the Low-Carbon Fuel Standard (LCFS) expected localities to analyze and mitigate the potentially destructive consequences of such food crop and food system-related biofuels. Yet remarkably, the DEIR is virtually devoid of any discussion of the environmental impact of this unavoidably massive upheaval in the nation's agricultural systems, with global implications.

Commenters' Scoping Comments provided the County with abundant information concerning the potential upstream environmental impact of the Project's proposed feedstocks, including through indirect land use changes.[79] The Scoping Comments offered reliable data that

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[78] Karras, 2021c.

[79] Scoping Comments, pp. 10.

indicates severe shortages in non-food crop sources such as waste oil and animal fats will necessarily require the Project to make use of large amounts of food crop oils, most notably soybean oil.[80] Commenters pointed to studies that have documented the unintended economic, environmental, and climate consequences of using fungible feedstock to produce biofuels. Although the environmental and climate impacts of each may vary in biofuel production, food crop oils share a basic chemical structure that allows them to be used interchangeably or substituted for each other in the market—a characteristic called fungibility. Most notably, Commenters documented the massive spike in demand for biofuel feedstocks that will be induced by the Project.[81]

The DEIR effectively disregards all this information. None of the extensive scientific research and data provided by Commenters concerning the potential upstream impact of food crop feedstocks is even referenced, much less considered.

Ultimately, the DEIR concludes, without any analysis resembling an evaluation of either displacement or induced land use changes, that the Project will have no impact on agricultural or forestry resources. DEIR at 4-1. It improperly narrows the geographic scope to "entirely within the developed areas of the Rodeo Site, Carbon Plant, and the Santa Maria Site." *Id*. As a result, the DEIR's very limited discussion and conclusions concerning upstream environmental impacts suffers from the following deficiencies, addressed at greater length in the sections below:

- *Misplaced reliance on the LCFS.* Implicitly, the DEIR appears to justify rejecting the Scoping Comments' concerns about the inducement land use changes based on the existence of the State's Low Carbon Fuel Standard (LCFS), which draws on an analysis of upstream impacts. DEIR at 4.6-212, 4.8-266, 4.8-284. That reliance is entirely misplaced.
- *Failure to fully describe feedstocks and their limited availability.* The DEIR fails to fully identify and analyze all potential feedstock the Project will be capable of processing. It merely states what feedstocks the Project's slate is "anticipated", DEIR at 3-25-27; *see* Section II), without describing the factors that will determine the feedstock slate. The DEIR makes a sweeping comment that feedstock combinations cannot be predicted with "any degree of certainty," but data collected for over a decade indicates otherwise. The analysis makes no reference to this exemplary data presented in the Scoping Comments concerning the limited availability of biofuel feedstocks, particularly for waste oils and animal fats, and the impact of that limited availability on the likely feedstock mix for the Project.[82]
- *Failure to address impact of feedstock fungibility with an indirect land use change (ILUC) and displacement analysis.* The DEIR does include a discussion of the fungibility of feedstock commodities, DEIR 3-27, but fails to follow through with the corresponding ILUC and displacement analyses that would allow the County to assess the environmental and climate impacts of ILUC and displacement changes.
- *Failure to address the magnitude of feedstock demand increase.* The Scoping Comments set forth the large percentage increase in demand for food system-related feedstocks of

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[80] Scoping Comments, pp. 12-14.

[81] Scoping Comments, pp. 13.

[82] *Id.*

the type proposed to be used for the Project. These enormous spikes receive no mention in the DEIR.

- *Failure to address environmental impacts from land use changes caused by feedstock demand increases.* There is now broad consensus that increased demand for food crop oil biofuel feedstock has induced land use changes with significant negative environmental and climate consequences. Of particularly great concern are the studies that document a link between increased demand for SBO to a dangerous increase in palm oil production.
- *Failure to meaningfully address mitigation of upstream environmental impacts.* Meaningful mitigation measures, not addressed in the DEIR, would include limiting use of the most harmful types of feedstocks and those likely to induce increased production of such feedstocks. It is likely that the County would need to limit at least two of the feedstock identified in the DEIR—SBO and DCO—as a mitigation measure.

A. Previous LCFS Program-Level CEQA Analysis Does Not Exempt the County from Analyzing Impacts Analysis of Project-Induced Land Use Changes and Mitigating Them

The DEIR includes numerous references to the California Low Carbon Fuel Standard (LCFS) crediting system. To the extent the County may take the position that any land use impacts have already been addressed in the environmental analyses to adopt and amend the LCFS, that position is unsupportable.[83] While CARB may have evaluated, considered, and hoped to mitigate greenhouse gas emissions from the transportation sector in the design of the LCFS, its land use change modeling was one factor in the quantification of carbon intensity (CI) and associated credits generated for an incremental unit of fuel. It does not purport to assess the impact of an *individual project,* which produces a specific volume of such fuel using a knowable array of feedstocks. That is the County's job in this CEQA review.

The LCFS analysis is not a substitute for CEQA because it does not establish or otherwise imply a significance threshold under CEQA Guidelines § 15064.7. The LCFS is a "scoring system" in that the quantity of LCFS credits available for each barrel of fuel produced is based on the fuel's "score"—its carbon intensity (CI). The DEIR uses broad language to describe how the LCFS considers the "complete life cycle" of a fuel. DEIR at 4.8-251. But the details matter. The LCFS calculates the *incremental* CI per barrel of production of covered fuels by incorporating multiple sources of associated carbon emissions, including those associated with feedstock-based land use changes. The LCFS uses the Global Trade Analysis Project (GTAP), which is mentioned in the DEIR, to incorporate the incremental carbon impact of feedstock-induced indirect land use changes (ILUC) in its incremental CI scoring system. CARB uses GTAP to estimate the amounts and types of land worldwide that are converted to agricultural production to meet fuel demand. [84] DEIR 3.8-13. A closer reading of a key CARB

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[83] DEIR 4.8-251, 4.8-3.

[84] In 2010, the LCFS ILUC analysis updated to using GTAP-BIO, which was designed to project the specific effects of one carefully defined policy change —namely the increased production of a biofuel. The methodology behind the change is detailed in Prabhu, A. Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels, California Environmental Protection Agency & Air Resources Board, 2015; Appendix I-6, 1-7, I-19. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/peerreview/050515staffreport_iluc.pdf (accessed Dec 8, 2021)[hereinafter CARB 2015 LCFS Staff Report ILUC]; *see also Appendix I: Detailed Analysis*

staff report on the LCFS ILUC analysis makes clear, "The GTAP-BIO analysis was designed to isolate the *incremental* contribution… GTAP-BIO projections are *incremental* and *relative*" (emphasis added).[85] The ILUC emission factors in the LCFS are calculated by averaging 30 GTAP scenarios with different input parameters per incremental unit increase in fuel demand,[86] disaggregating the land use change estimates by world region and agro[87] [88] This incremental adjustment of CI values is useful for augmenting incremental units of biofuel production based on carbon emissions from associated land use changes, but no more.

As a marginal tool, the LCFS ILUC modeling does not set or have a threshold that could distinguish between significant and insignificant impacts under CEQA. The LCFS can determine the incremental CI of one barrel per day of biofuel production, but it says nothing about what happens when an individual project produces a finite amount of fuel. As a result, the LCFS cannot tell you if 80,000 b/d of additional biofuel feedstock consumption —and its associated environmental and climate impacts—is a little or a lot, insignificant or significant.

Indeed, the 2018 LCFS Final EA indicates that state regulators did not intend for the LCFS to be a replacement for CEQA review of individual projects. The 2018 LCFS Final EA explicitly explains that the environmental review conducted was only for the LCFS program—*not* for individual projects. It repeatedly states, "the programmatic level of analysis associated with this EA does not attempt to address project-specific details of mitigation…"[89] and defers to local agencies like the County who have the "authority to determine project-level impacts and require project-level mitigation…for individual projects."[90] The County not only has the authority, but also the duty to determine project-level land use impacts and require project-level mitigation.

Finally, the LCFS only addresses carbon emissions, as it is designed to assign a CI score to fuels. It thus does *not* address non-carbon impacts associated with land use change. These impacts, as discussed further below, can be ecologically devastating. LCFS CI calculations are not designed to capture the full range of impacts associated with deforestation and other land use changes that may be wrought by increased production of biofuel feedstock crops.[91] Following the guidance of the 2018 LCFS Final EA, it is up to a project-specific DEIR to analyze the

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for Indirect Land Use Change in Low Carbon Fuel Standard Regulation Staff Report: Initial Statement of Reasons for Proposed Rulemaking, California Air Resources Board, Jan 2015, I-1, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/lcfs15appi.pdf (accessed Dec 8, 2021) [hereinafter CARB 2015 LCFS Staff Report ILUC Appendix].

[85] CARB 2015 LCFS Staff Report ILUC Appendix I-20.

[86] CARB 2015 LCFS Staff Report ILUC Appendix I-8, I-16.

[87] CARB 2015 LCFS Staff Report ILUC Appendix I-13.

[88] CARB 2015 LCFS Staff Report ILUC Appendix Attachment 3-1.

[89] CARB analyzed the Conversion of Agricultural and Forest Resources Related to New Facilities, Agricultural and Forest Resource Impacts Related to Feedstock Cultivation and Long-Term Operational Impacts Related to Feedstock Production. *See* Final Environmental Analysis Prepared For The Proposed Amendments To The Low Carbon Fuel Standard And The Alternative Diesel Fuels Regulation, California Air Resources Board: Sacramento, CA, 2018; https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/finalea.pdf (accessed Dec 8, 2021) (hereinafter CARB 2018 LCFS Final EA).

[90] *Id.*

[91] *Id.*

agricultural, forest, soil and water impacts related to land use changes because this analysis is specific to the geographic source of the feedstock crops.

In sum, the County cannot rely on the LCFS as a basis to abdicate its duty to disclose, analyze, and mitigate Project-induced land use changes in the DEIR. That the LCFS passed through program-level environmental review does not exempt any and all individual fuel production projects from CEQA review simply because they might qualify for LCFS subsidies. It is imperative that the DEIR evaluate all effects of use of potential food-grade feedstocks on upstream land use and agricultural systems, and the environmental impacts associated with those effects.

B. The DEIR Should Have Specified That the Project Will Rely Largely on Non-Waste Food System Oils, Primarily Soybean Oil [92]

The Project would convert existing crude oil refining equipment for use in HEFA refining. DEIR at 3.9 *et seq*.[93] The only HEFA feedstocks available in commercially relevant amounts for biofuel refining are from land-based food systems.[94] These include the ones listed in the DEIR: "used cooking oil (UCO); fat, oil and grease (FOG); tallow (animal fat); inedible corn oil (also known as distillers corn oil or DCO); soybean oil (SBO); canola oil; other vegetable-based oils and/or emerging and other next-generation feedstock." DEIR at 3.82. However, as noted above in the previous subsection, the DEIR reflects no commitment to use these in any particular proportion.

The law requires more. Even to the extent Phillips 66 is unable to specify the exact amount of each feedstock that will be used in the Project year to year, the County should have evaluated a "reasonable worst case scenario" for feedstock consumption and its impacts. *See Planning and Conservation League v. Castaic Lake Water Agency* (2009), 180 Cal.App.4th 210, 252; *Sierra Club v. Tahoe Regional Planning Agency*, 916 F.Supp.2d 1098, 1151-52 (E.D.Cal. 2013). While the County was not required to address entirely speculative worst case scenarios, neither may it use the mere existence of uncertainty as justification to avoid addressing any feedstock-varying scenarios at all. *Id.* Neither is analysis *only* of the reasonable worst case scenario necessarily sufficient – the County was required to evaluate a reasonable array of scenarios, including but not necessarily limited to the worst case scenario, in order to provide full disclosure. *City of Long Beach v. City of Los Angeles* (2018), 19 Cal.App.5th 465, 487-88.

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[92] Portner, H.O. et al., Scientific outcome of the IPBES-IPCC co-sponsored workshop on biodiversity and climate change, IPBES Secretariat, June 2021, 18-19, 28-29, 53-58. https://www.ipbes.net/events/launch-ipbes-ipcc-co-sponsored-workshop-report-biodiversity-and-climate-change (accessed Dec 8, 2021).

[93] Although as discussed in Section II, the DEIR never specifically mentions HEFA, the description generally references that technology, *i.e.,* briefly noting that the process feeds lipids, and more specifically, lipids from triacylglycerols (TAGs), and fatty acids cleaved from those TAGs, from biomass into the refinery.

[94] While fish oils are commercially available, they are extremely limited in availability. Food and Agriculture Organization of the United Nations (FAO), *The State of World Fisheries and Aquaculture: Sustainability in action*, 2020. http://www.fao.org/documents/card/en/c/ca9229en (accessed Dec 12, 2021); *see also* Yusuff, A., Adeniyi, O., Olutoye M., and Akpan, U. *Waste Frying Oil as a Feedstock for Biodiesel Production*, IntechOpen, 2018. http://dx.doi.org/10.5772/intechopen.79433 (accessed Dec 8, 2021).

Whether the list is exclusive or not, appropriate DEIR impact analysis should reflect historic, current, and projected feedstock availability that will influence the proportional selection of feedstocks as demand for feedstock increases. While the DEIR acknowledges that market forces will also influence the selection of feedstocks, DEIR at 3-27, the County cannot ignore this readily available information about feedstock availability. Under CEQA, the County must still identify analyze the significance of the foreseeable feedstock mix scenarios—including a reasonable worst case scenario—accordingly.

Had it done so, the County would have determined that the very large majority of the feedstock the Project will use will almost certainly come from food crop and food system oils—predominantly SBO but also potentially others like DCO —with very little coming from waste oils such as tallow. One indicator for the likely predominant role of SBO and other food crop oils for the Project is the current breakdown of feedstock *demand* for biodiesel (another lipid-based biofuel) production.[95] From 2018 to 2020, 59% of biodiesel in the United States was produced from SBO as feedstock, compared to 11% from yellow grease, 14% from DCO, and only 3% from tallow, or rendered beef fat.[96] Another indicator is the limited domestic *supply* of alternative feedstock sources. Tallow and other waste oil volumes have come nowhere near meeting current biodiesel feedstock demand, with little prospect of expanding soon.[97] The future possible supply for these wastes is substantially constrained by the industries that produce them, and as such are generally nonresponsive to increased levels of demand. As a result, supplies will likely only increase at the natural pace of the industries that produce them.[98] Thus, a large fraction of feedstock likely to be used for the Project will be food crop oils – both purpose-grown food crop oils, such as SBO, canola, rapeseed, and cottonseed oils; and oils currently used in the food system, such as DCO.

C. The Project's Use of Feedstocks From Purpose-Grown Crops For Biofuel Production Is Linked to Upstream Land Use Conversion

There is now broad consensus in the scientific literature that increased demand for food crop oil biofuel feedstock has induced or indirect land use changes (ILUC) with significant negative environmental and climate consequences.[99] ILUC is already widely considered in

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[95] *See* Zhou, Y; Baldino, C; Searle, S. *Potential biomass-based diesel production in the United States by 2032*. Working Paper 2020-04. International Council on Clean Transportation, Feb. 2020, https://theicct.org/sites/default/files/publications/Potential_Biomass-Based_Diesel_US_02282020.pdf (accessed Dec 8, 2021).

[96] Uses data from EIA Biodiesel Production Report, Table 3. Feedstock breakdown by fat and oil source based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil). *See also* Zhou, Baldino, and Searle, 2020-04.

[97] *See* Baldino, C; Searle, S; Zhou, Y, *Alternative uses and substitutes for wastes, residues, and byproducts used in fuel production in the United States*, Working Paper 2020-25, International Council on Clean Transportation, Oct. 2020, https://theicct.org/sites/default/files/publications/Alternative-wastes-biofuels-oct2020.pdf (accessed Dec 8, 2021).

[98] *See* Zhou, Baldino, and Searle, 2020-04.

[99] *See* Portner et al., 2021.; *see also* Searchinger, T. et al., *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change*. Science, 2008, 319, 1238,

policies to evaluate the environmental benefits of biofuels relative to fossil fuel counterparts, including the California Low-Carbon Fuel Standard, Renewable Fuel Standard (RFS),[100] EU Renewable Energy Directive (RED) and RED II,[101] and ICAO CORSIA[102]. After a decade of studies, soybean oil will likely be designated a high-ILUC risk biofuel that will be phased out of European Union renewable energy targets by 2030. [103] Belgium has already banned soybean oil-based biofuels as of 2022.[104]

HEFA biofuels can result in ILUC in several ways. One way is through the additional lands converted for crop production as feedstock demand for that crop increases. In simple economic terms, increased HEFA biofuel production requires increased feedstock crops, resulting in increased prices for that feedstock crop. The price increases then cause farmers of existing cultivated agricultural land to devote more of such land to that crop as it becomes more lucrative,[105] and are incentivized to clear new land to meet increased demand.[106][107]

A second way that HEFA biofuels can cause ILUC, most relevant for the feedstocks proposed for the Project, is through displacement and substitution of commodities, leading to the conversion of land use for crops other than that of the feedstock demanded. As mentioned above, oil crops are to a great degree fungible—they are, essentially, interchangeable lipid, triacylglycerol (TAG) or fatty acid inputs to products. Due to their fungibility, their prices are

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https://science.sciencemag.org/content/319/5867/1238 (accessed Dec 8, 2021) (This landmark article notes one of the earliest indications that certain biofuel feedstock are counterproductive as climate measures.)

[100] O'Malley, J. *U.S. biofuels policy: Let's not be fit for failure*, International Council on Clean Transportation, Oct. 2021, https://theicct.org/blog/staff/us-biofuels-policy-RFS-oct21 (accessed Dec 11, 2021).

[101] Currently, the European Union is phasing out high ILUC fuels to course correct their biofuel policies based on nearly a decade of data. Adopted in 2019, Regulation (EU) 2019/807 phases out high ILUC-risk biofuels from towards their renewable energy source targets by 2030. ILUC – High and low ILUC-risk fuels, Technical Assistance to the European Commission. https://iluc.guidehouse.com/ (accessed Dec 8, 2021).

[102] International Civil Aviation Organization (ICAO), "CORSIA Supporting Documents: CORSIA Eligible Fuels – Life Cycle Assessment Methodology," 2019. https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA%20Supporting%20Document_CORSIA%20Eligible%20Fuels_LCA%20Methodology.pdf (accessed Dec 11, 2021).

[103] Malins, C. *Risk Management: Identifying high and low ILUC-risk biofuels under the recast Renewable Energy Directive*; Cerulogy, 2019; 4, 14. http://www.cerulogy.com/wp-content/uploads/2019/01/Cerulogy_Risk-Management_Jan2019.pdf (accessed Dec 8, 2021).

[104] Belgium to ban palm- and soy-based biofuels from 2022. Argus Media, Apr. 14, 2021. https://www.argusmedia.com/en/news/2205046-belgium-to-ban-palm-and-soybased-biofuels-from-2022 (accessed Dec 8, 2021).

[105] *See Appendix I: Detailed Analysis for Indirect Land Use Change in Low Carbon Fuel Standard Regulation Staff Report: Initial Statement of Reasons for Proposed Rulemaking,* California Air Resources Board, Jan 2015, I-1, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/lcfs15appi.pdf (accessed Dec 8, 2021) (hereinafter CARB 2015 LCFS Staff Report ILUC Appendix).

[106] *Id.*

[107] Lenfert et al., *ZEF Policy Brief No. 28;* Center for Development Research, University of Bonn, 2017. www.zef.de/fileadmin/user_upload/Policy_brief_28_en.pdf; Gatti, L.V., Basso, L.S., Miller, J.B. et al. Amazonia as a carbon source linked to deforestation and climate change. *Nature* 595, 388–393 (2021). https://doi.org/10.1038/s41586-021-03629-6 (accessed Dec 8, 2021); Nepstad, D., and Shimada, J., *Soybeans in the Brazilian Amazon and the Case Study of the Brazilian Soy Moratorium,* International Bank for Reconstruction and Development / The World Bank, Washington, D.C., 2018 (accessed Dec 8, 2021); Rangaraju, S, 10 years of EU fuels policy increased EU's reliance on unsustainable biofuels, Transport & Environment, Jul 2021. https://www.transportenvironment.org/wp-content/uploads/2021/08/Biofuels-briefing-072021.pdf (accessed Dec 8, 2021).

significantly if not wholly linked: when the price of one crop increases, another cheaper crop will be produced in greater volumes to fill the gap as consumers substitute their use of the more expensive crop. This substitution effect is known as displacement.[108] Studies have extensively documented the linkage between rising prices for one biofuel feedstock oil crop and the expanding production of another substitute oil crop.[109] These effects have been demonstrated for at least three of feedstocks identified in the DEIR—SBO, DCO, and tallow – that are significantly likely to be used in the Project.

Soybean Oil (SBO): SBO accounts for only about a third of the total market value of whole soybeans, with the majority of the value in the soybean meal. As a result, SBO supply is only weakly responsive to its own price—meaning that as demand for soybean oil increases, domestic SBO supply is unlikely to increase substantially.[110] However, the supply of *palm oil* does respond to SBO prices. Historical data show that SBO price increases lead to increased imports of palm oil, as domestic consumers substitute SBO with palm oil. .[111] [112] The price of SBO, which would be the predominant source of feedstock in this Project, is already skyrocketing, in part in connection with increased biofuel production.[113] By proposing a Project that will heavily rely on SBO, the Project will exacerbate the trends of increasing palm oil production and use because of rising SBO prices because of feedstock fungibility.

DCO: Distiller's corn oil (DCO) is a co-product produced during ethanol production, alongside another co-product, distiller's grains with solubles (DGS).[114] DCO can be extracted

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[108] *See generally* Pavlenko, N. and Searle, S. *Assessing the sustainability implications of alternative aviation fuels*. Working Paper 2021-11. International Council on Clean Transportation, Mar 2021. https://theicct.org/sites/default/files/publications/Alt-aviation-fuel-sustainability-mar2021.pdf (accessed Dec 8, 2021).

[109] *See* Malins, C. *Thought for food: A review of the interaction between biofuel consumption and food markets*, Transport & Environment, Sept 2017. https://www.transportenvironment.org/wp-content/uploads/2021/07/Cerulogy_Thought-for-food_September2017.pdf (accessed Dec 8, 2021).

[110] *See* Martin, J. '*Soybean freakonomics'* in *Everything You Ever Wanted to Know About Biodiesel (Charts and Graphs Included!)* Union of Concerned Scientists, The Equation, Jun 22, 2016. https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel/ (accessed Dec 8, 2021).

[111] *See* Santeramo, F. and Searle, S. *Linking soy oil demand from the US Renewable Fuel Standard to palm oil expansion through an analysis on vegetable oil price elasticities*. Energy Policy 2018, 127, 19 https://www.sciencedirect.com/science/article/abs/pii/S0301421518307924 (accessed Dec 8, 2021).

[112] Searle, S. *How rapeseed and soy biodiesel drive oil palm expansion*, The International Council on Clean Transportation, Jul 2017. https://theicct.org/publications/how-rapeseed-and-soy-biodiesel-drive-oil-palm-expansion (accessed Dec 8, 2021).

[113] *See* Walljasper, C. GRAINS–Soybeans extend gains for fourth session on veg oil rally; corn mixed. *Reuters*, Mar 24 2021. https://www.reuters.com/article/global-grains-idUSL1N2LM2O8 (accessed Dec 8, 2021).

[114] Malins, C., Searle, S., and Baral, A., *A Guide for the Perplexed to the Indirect Effects of Biofuels Production*, International Council on Clean Transportation 2014, 80 ("Co-products can be broadly placed into two categories: those that directly displace land-based products and have land use implications, such as distillers grains with solubles (DGS) displacing soybean meal, and those that displace non-land-based products such as urea, glycerol, and electricity. Co-products in the second category do not have land use implications but have greenhouse gas (GHG) reduction implications."). https://theicct.org/sites/default/files/publications/ICCT_A-Guide-for-the-Perplexed_Sept2014.pdf (accessed Dec 8, 2021).

from distiller's grains with solubles (DGS), leading to substitution effects between the two commodities.[115] DGS is a valuable agricultural residue commonly used in animal feed. In response to recently increasing biofuel feedstock demand, ethanol producers have been increasingly extracting DCO from DGS.[116] Yet extracting DCO from DGS feed also removes valuable nutrients, requiring farmers to add even more vegetable oils or grains to replace the lost calories in their livestock feed.[117] In practice, the most economical, and common source for these replacement nutrients has been more DCO, or DGS containing DCO, both of which then require additional corn crops.[118] Thus, while DCO is not an oil from purpose-grown crops, any increase in DCO demand for Project biofuel production will ultimately increase food corn crop demand.[119]

Tallow: Tallow represents a small portion of the total value of cattle, less than 3%, and as a result, increased demand for tallow will only result in marginal increases in tallow supply, even with substantial price increases.[120] Like several other animal fats and DCO, tallow is not truly a waste fat, because it has existing uses. Tallow is currently used for livestock feed; pet food, for which it has no substitute; and predominantly, the production of oleochemicals like wax candles, soaps, and cosmetics.[121] As a result, the dominant impact of increased tallow demand is through diversion of existing uses. Therefore, increased tallow production will likely yield increased palm oil and corn oil production.[122]

D. The Scale of This Project Would Lead to Significant Domestic and Global Land Use Conversions

As shown above, all of the feedstocks demanded by the Project would lead to either direct or indirect increases in crops, such as soy, oil palm, and corn, which will require land use conversion. These potential land use impacts are of particular concern with respect to a project of the magnitude proposed by Phillips 66, given its potential to significantly disrupt food crop agricultural patterns.

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[115] *Id*. at 79.

[116] Searle, S. *If we use livestock feed for biofuels, what will the cows eat?* The International Council on Clean Transportation, Jan. 2019. https://theicct.org/blog/staff/if-we-use-livestock-feed-biofuels-what-will-cows-eat (accessed Dec 8, 2021).

[117] *See* Final Rulemaking for Grain Sorghum Oil Pathways. 81 Fed. Reg. 37740-37742 (August 2, 2018), https://www.govinfo.gov/content/pkg/FR-2018-08-02/pdf/2018-16246.pdf (accessed Dec 8, 2021); *see also* EPA sets a first in accurately accounting for GHG emissions from waste biofuel feedstocks, International Council on Clean Transportation Blog (Sept. 2018), https://theicct.org/blog/staff/epa-account-ghg-emissions-from-waste (accessed Dec 8, 2021).

[118] Searle 2019.

[119] Gerber, P.J. et al., *Tackling climate change through livestock—A global assessment of emissions and mitigation opportunities*, Food and Agriculture Organization of the United Nations 2013, 8. https://www.fao.org/3/i3437e/i3437e.pdf (accessed Dec 8, 2021).

[120] Pavlenko, N. and Searle, S. *A comparison of methodologies for estimating displacement emissions from waste, residue, and by-product biofuel feedstocks*, Working Paper 2020-22, International Council on Clean Transportation, Oct 2020, 6. https://theicct.org/sites/default/files/publications/Biofuels-displacement-emissions-oct2020.pdf (accessed Dec 8, 2021).

[121] Baldino, Searle, and Zhou, 2020-25, pp. 6.

[122] Pavlenko and Searle 2020-22, pp. 26.

The DEIR failed to address the significant impact of the Project's demand for food crop feedstocks on agricultural markets, and hence on land use. The volume of food crop oil feedstock, namely SBO, likely to be required for the Project represents a disproportionately large share of current markets for such feedstock.[123] The anticipated heavy spike in demand for food crop oils associated with the Project (not to mention the cumulative spike when considered together with other HEFA projects such as the Marathon Martinez Refinery, *see* Section IX) will have significant environmental impacts, as discussed in the next subsection.

To assess the significance the Project's anticipated feedstock use, the County could and should have analyzed the Project's proposal to consume up to 80,000 b/d of lipid feedstocks[124] in the context of both total biofuel demand and total agricultural production data. With respect to biofuel demand, data from the U.S. Energy Information Administration on total biodiesel production in the United States indicates that oil crop and animal fat demand associated with U.S. biodiesel production on average totaled approximately 113,000 barrels per day (b/d) for the time period 2018-2020.[125] The Project would increase this nationwide total by a full 71 percent.[126]

With respect to total production, US agricultural yield of the types of oil crops and animal fats that are potentially usable as Project feedstocks was roughly 372,000 b/d on average.[127] Thus, the Project alone would consume approximately a 22 percent share[128] of current total US production of lipid feedstocks. With that increase from the Project in place, U.S. biofuel feedstock demand could claim as much as 52 percent of total U.S. farm yield for *all* uses of these

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[123] *See* Karras, G. Biofuels: Burning Food?, Community Energy resource, 2021. https://f61992b4-44f8-48d5-9b9d-aed50019f19b.filesusr.com/ugd/bd8505_a077b74c902c4c4888c81dbd9e8fa933.pdf (accessed Dec 8, 2021).

[124] DEIR xxii.

[125] Uses EIA data from the Monthly Biodiesel Production Report, Table 3. This 113,000 b/d estimate is based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil).

[126] DEIR xxii . The Project percentage boost over existing biofuel feedstock consumption is from 80,000 b/d, divided by that 113,000 b/d from existing biodiesel production.

[127] This 372,000 b/d estimate is from two sources. First, data were taken from the U.S. Department of Agriculture (USDA) "Oil Crops Data: Yearbook Tables" data. U.S. Department of Agriculture (USDA), Oil Crops Yearbook Tables 5, 26, and 33, Mar. 26, 2021, https://www.ers.usda.gov/data-products/oil-crops-yearbook/ (accessed Dec. 14, 2021). Specifically, from Oct. 2016 through Sep. 2020 average total U.S. yields were: 65.1 million pounds per day (MM lb/d), or 202,672 b/d at a specific gravity (SG) of 0.916 for soybean oil (*see* i below), 4.62 MM lb/d or 14,425 b/d at 0.915 SG for canola oil (ii), and 15.8 MM lb/d or 49,201 b/d at 0.923 SG for corn oil (iii).. *See* USDA Oil Crops Yearbook (OCY) data tables (i) OCY Table 5, (ii) OCY Table 26, (iii) OCY Table 33, (iv) OCY Table 20), (v) OCY Table 32. Second, we estimated total U.S. production of other animal fats and waste oils from the U.S. Department of Agriculture (USDA) "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks" Annual Summaries. National Agricultural Statistics Service, "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks Annual Summary", 2017 through 2020, https://usda.library.cornell.edu/concern/publications/mp48sc77c. (accessed Dec. 14, 2021). Specifically, from 2017 to 2020, average total U.S. yields were: 16.2 MM lb/d or 51,386 b/d for edible, inedible, and technical tallow production, 6.65 MM lb/d or 22,573 b/d for poultry fat production, 4.52 MM lb/d or 13,420 b/d for lard and choice white grease production, and 5.83 MM lb/d or 18,272 b/d for yellow grease production.

[128] This figure represents Project feedstock demand of 80,000 b/d over the estimated 372,000 b/d total lipid production in the U.S. calculated in the previous footnote.

oils and fats. The Project alone would thus commit a disproportionate share of US food crop oils to California, with attendant potential climate consequences.[129]

The projected impact of the Project on the SBO markets is particularly notable. Existing biodiesel production uses approximately 66,000 b/d of SBO out of the total 203,000 b/d of SBO produced domestically for all uses.[130] As a result, the Project alone could use up to 39 percent of total domestic SBO production. This would constitute a rapid increase in domestic SBO consumption, which would dramatically outpace the recent year-on-year increases in domestic SBO production, ranging from 1-7%. This in turn would lead to rapid price spikes and substitution across the oil markets.

In order to assess the impacts of a "reasonable worst case" scenario, the County could, and should, have calculated the magnitude of the land use changes attributable to the anticipated feedstock mix. Had the County taken a closer look at the environmental assessment of the LCFS itself, it could have readily used the same analysis conducted by CARB for the LCFS, as previously discussed in subsection A in order to quantify the upstream land use impacts of the Project's use of SBO feedstock. For example, under a hypothetical "shock" increase of 0.812 billion gallons per year of soy biodiesel, the GTAP-BIO model identified an average of over 2 million acres of forest, pasture, and cropland-pasture land would be converted to cropland. The majority of this land use change would be overseas, with 1.2 million acres of the converted land use outside of the U.S.[131] While land use impacts will not necessarily be linear with the feedstock demand increases, this finding can be extrapolated to estimate the land use converted as a result of the Project. This finding, if scaled to the 1.23 billion gallons of feedstock consumed by the Project and if 100% of that feedstock was SBO, would mean 3.0 million acres of land would need to be converted for this Project.

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[129] Importing biofuel feedstock from another state or nation which is needed there to help decarbonize its economy could make overreliance on biofuels to help decarbonize California's economy counterproductive as a climate protection measure. Accordingly, expert advice commissioned by state agencies suggests limiting the role of biofuels within the state's decarbonization mix to the state's per capita share of low-carbon biofuel feedstocks. *See* Mahone et al. 2020 and 2018. On this basis, given California and U.S. populations of 39.5 and 330 million, respectively, California's total share of U.S. farm production (for all uses) of plant oils and animal fats which also are used for biofuels would be approximately 12%. As described in the note above, however, the Project could commit 22% of that total U.S. yield (for all uses) to biofuels produced at the Refinery alone.

[130] U.S. Department of Agriculture (USDA) "Oil Crops Data: Yearbook Tables." Table 5 https://www.ers.usda.gov/data-products/oil-crops-yearbook/oil-crops-yearbook/#All%20Tables.xlsx?v=7477.4 (accessed Dec 12, 2021); U.S. Energy Information Administration (EIA). Monthly Biodiesel Production Report, Table 3. Inputs to biodiesel production; www.eia.gov/biofuels/biodiesel/production/table3.xls (accessed Dec 12, 2021). Soybean oil consumed for biodiesel production is an average of 2018 through 2020 data, while total U.S. production is an average from Oct. 2016 through Sept. 2020.

[131] 2018 CARB LCFS Staff Report Appendix I-8, I-29, I-30.

E. Land Use Conversions Caused By the Project Will Have Significant Non-Climate Environmental Impacts

The land use changes incurred by increased use of feedstock supplies risk an array of environmental impacts related to habitats, human health, and indigenous populations.[132] Conversion of more natural habitat to cropland is often accompanied by efforts to boost short-term yields by applying more fertilizers and pesticides, thereby destroying habitat needed to reverse biodiversity loss. Indeed, authoritative international bodies have warned explicitly about the potential future severity of these impacts.[133] One path for creating additional crop lands is by burning non-agricultural forests and grasslands. This destructive process not only releases sequestered carbon, but also causes non-carbon related environmental impacts due to use of nitrogen-based fertilizers and petroleum-derived pesticides on the newly cleared lands; and use petroleum-fueled machinery to cultivate and harvest feedstock crops from newly converted land to meet crop-based biofuel demand.[134]

These non-climate environmental impacts were even identified by the 2018 LCFS Final EA as significant negative environmental impacts. CARB concluded that the agricultural, forest, and water resources related to land use changes related to feedstock cultivated would likely have significant negative effects, which are extraneous to the LCFS CI calculation. Adverse effects associated with the conversion or modification of natural land or existing agriculture include impacts on sensitive species populations; soil carbon content; annual carbon sequestration losses, depending on the land use; long-term erosion effects; adverse effects on local or regional water resources; and long-term water quality deterioration associated with intensified fertilizer use, pesticide or herbicide run-off; energy crops and short rotation forestry on marginal land, and intensive forest harvest could both have long-term effects on hydrology; agricultural activities may cause pollution from poorly located or managed animal feeding operations; pollutants that result from farming and ranching may include sediment, nutrients, pathogens, pesticides, metals, and salts; increased use of pesticides could increase greenhouse gas emissions.[135]

The expansion of palm oil production, due to SBO consumption as described above, will also have a particularly severe environmental impact.[136] The palm oil industry is a source of pollutants and greenhouse gas emissions in two ways: deforestation and the processing of palm

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[132] Malins, C., *Soy, land use change, and ILUC-risk: a review*, Cerulogy, 2020a, https://www.transportenvironment.org/wp-content/uploads/2021/07/2020_11_Study_Cerulogy_soy_and_deforestation.pdf; Malins, C. *Biofuel to the fire – The impact of continued expansion of palm and soy oil demand through biofuel policy*. Report commissioned by Rainforest Foundation Norway, 2020b. https://d5i6is0eze552.cloudfront.net/documents/RF_report_biofuel_0320_eng_SP.pdf (accessed Dec 8, 2021); Garr, R. and Karpf, S., BURNED: Deception, Deforestation and America's Biodiesel Policy, Action Aid USA, 2018. https://www.actionaidusa.org/publications/americas-biodiesel-policy/ (accessed Dec 8, 2021).

[133] IPBES Summary for policymakers of the global assessment report on biodiversity and ecosystem services of the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services. IPBES: Bonn, DE, 2019, pp. 12, 18, 28. https://ipbes.net/global-assessment (accessed Dec 8, 2021).

[134] CARB 2018 LCFS Final EA, pp. 120, 172-173.

[135] CARB 2018 LCFS Final EA, pp. 110 – 120.

[136] *See* Petrenko, C., Paltseva, J., and Searle, S. *Ecological Impacts of Palm Oil Expansion in Indonesia*, International Council on Clean Transportation, Jul 2016. https://theicct.org/sites/default/files/publications/Indonesia-palm-oil-expansion_ICCT_july2016.pdf (accessed Dec 8, 2021).

oil. Fires clearing the way for a palm oil plantation are a major source of air pollution that adversely affect human health; agrochemicals associated with palm oil plantations are dangerous for terrestrial and aquatic ecosystems.[137] Palm oil production also proliferates in highly productive biodiversity hotspots like Indonesia and the Brazilian Amazon, where massive deforestation and attendant species loss can dramatically affect both global biodiversity and the climate.[138]

F. Land Use Conversions Caused by the Project Will Have Significant Climate Impacts

The County failed to address evidence that increased use of food crop or food system feedstocks like palm and soybean oil have resulted in net increases in greenhouse gas emissions. As noted above, while the LCFS takes into account climate impacts resulting from land use change in its CI calculations, those calculations are expressly not intended to substitute for project-level analysis of impacts.

As described in the previous subsection, when the increased consumption of palm and soybean oil results in the clearing of more land or deforestation to grow more of those crops, it leads to the counterproductive destruction of natural carbon sinks. This expansion of soy production not only results in carbon loss from the destruction of vegetation and upheaval of high carbon stock soil, but also the loss of future sequestration capabilities. Available analysis suggests that a significant fraction of cropland expansion in general, and soy expansion in particular, continues to occur at the expense of carbon-sequestering forests, especially in South America.[139] Greenhouse gas emissions induced by land use changes from increased demand for food crop or food system-based feedstock also occur in the United States. One recent study concluded "perhaps surprisingly—that despite the dominance of grassland conversion in the US, emissions from domestic [land use change] are greater than previously thought."[140] More than 90% of emissions from grassland conversions came from soil organic carbon stocks (SOC).[141] Due to the longtime accumulation time of the SOCs, those emissions may be impossible to mitigate on a time scale relevant to humans.[142]

Domestic and global climate impacts from land use changes are interconnected because the feedstock are tied to a global food system. For example, even if the feedstock source is domestic, the increase in soybean oil demand will result in increases in palm oil production expansion as described above—ultimately resulting in substantial increases in GHG emissions.[143] As a result, modeled soy-based biofuel net carbon emissions are, at best, virtually the same as fossil diesel, with even worse climate impacts for greater quantities of soy-based

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[137] *Id.,* pp. 7-11.
[138] *Id.*
[139] Malins 2019, pp. 5.
[140] Spawn, S. et al. *Carbon emissions from cropland expansion in the United States* Environ. Res. Lett. 14 045009, 2019. https://iopscience.iop.org/article/10.1088/1748-9326/ab0399 (accessed Dec 11, 2021).
[141] Spawn 2019, pp. 5.
[142] Spawn 2019, pp. 7, 9.
[143] Malins, C. Driving deforestation: The impact of expanding palm oil demand through biofuel policy, 2018. http://www.cerulogy.com/wp-content/uploads/2018/02/Cerulogy_Driving-deforestation_Jan2018.pdf (accessed Dec 12, 2021); *see also* Malins 2020, pp. 57; *see generally* Searle 2018.

biofuel produced.[144] These estimates suggest the DEIR has dramatically overstated the potential GHG benefits of the Project.

G. The County Should Have Taken Steps to Mitigate ILUC Associated with the Project by Capping Feedstock Use

The County should have considered a feedstock cap as a mitigation measure for land use impacts, but did not.[145] The one mitigating measure it did mention, best management practices (BMPs), has no meaningful application here.

Best Management Practices: BMPs for feedstock crops should have been considered and included as a mitigation measure. The 2018 LCFS EA indicates that CARB anticipated local governments like the County to use their land use authority to mitigate projects by requiring feedstock sources to be developed under Best Management Practices specific to the ecological needs of feedstock origins. In particular, CARB left localities with land use authority to consider BMPs to mitigate long-term effects on hydrology and water quality related to changes in land use and long-term operational impacts to geology and soil associated with land use changes. [146]

Feedstock Cap: To guard against the severe environmental impacts associated with the inevitably induced land use changes, the County should set capped feedstock volume, at a level that would prevent significant ILUC impacts. The DEIR should have considered both caps on individual feedstocks, and an overall cap on feedstock volume. Such limits would be based on an ILUC assessment of each potential feedstock and total combinations of feedstock. In particular, the County should take steps to ensure that California does not consume a disproportionate share of available feedstock, in exceedance of its per capita share, in accordance with the prudent assumptions in CARB's climate modeling.[147]

V. THE DEIR FAILS TO ASSESS AND MITIGATE PROCESS SAFETY RISKS ASSOCIATED WITH RUNNING BIOFUEL FEEDSTOCKS[148]

The Scoping Comments described how processing vegetable or animal-derived biofuel feedstocks in a hydrotreater or hydrocracker creates significant refinery-wide process hazards beyond those that attend crude oil refining. That information was disregarded and not addressed in the DEIR. It is essential that the DEIR address the process safety risks described in the subsections below, and evaluate their potential impact on human health.

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[144] Malins 2020a, pp. 57.

[145] *See e.g.*, Mitigation B.2.b: Agricultural and Forest Resource Impacts Related to Feedstock Cultivation; Mitigation Measure B.7.b Long-Term Operational Impacts to Geology and Soil Associated with Land Use Changes; Mitigation B.10.b: Long-Term Effects on Hydrology and Water Quality Related to Changes in Land Use, Mitigation B.11.b: Long-Term Operational Impacts on Land Use Related to Feedstock Production.

[146] *See* Mitigation Measure B.7.b Long-Term Operational Impacts to Geology and Soil Associated with Land Use Changes; Mitigation B.10.b: Long-Term Effects on Hydrology and Water Quality Related to Changes in Land Use.

[147] California Air Resources Board, PATHWAYS Biofuel Supply Module, Technical Documentation for Version 0.91 Beta, Jan 2017, pp. 9 https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/bfsm_tech_doc.pdf.

[148] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "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."

A. The Project Could Worsen Process Hazards Related to Exothermic Hydrogen Reactions

Running biofuel feedstocks risks additional process safety hazards even beyond those associated with processing crude oil. This is because the extra hydrogen that must be added to convert the new biofuel feedstock to hydrocarbon fuels generates more heat in process reactions that occur under high pressure and are prone to runaway reactions. The reaction is exothermic: it generates heat. When it creates more heat, the reaction can feed on itself, creating more heat even faster.[149]

The reason for the increased heat, and hence risk, is that the removal of oxygen from triacylglycerols of fatty acids in the biofuel feed, and saturating the carbon atoms in that feed to remove that oxygen without creating unwanted carbon byproducts that cannot be made into biodiesel and foul the process catalyst, require bonding that oxygen and carbon with a lot more hydrogen. The Project would use roughly nine times more hydrogen per barrel biorefinery feed than the average petroleum refinery needs from hydrogen plants per barrel crude.[150] Reacting more hydrogen over the catalyst in the hydrotreating or hydrocracking reactor generates more heat faster.[151] This is a well-known hazard in petroleum processing, that manifests frequently in flaring hazards[152] when the contents of high-pressure reactor vessels must be depressurized[153] to flares in order to avoid worse consequences that can and sometimes have included destruction of process catalyst or equipment, dumping gases to the air from pressure relief valves, fires and explosions. The extra hydrogen reactants in processing the new feedstocks increase these risks.[154]

B. The Project could Worsen Process Hazards Related to Damage Mechanisms Such as Corrosion, Gumming, and Fouling

The severe processing environment created by the processing of new feedstocks for the Project also can be highly corrosive and prone to side reactions that gum or plug process flows, leading to frequent or even catastrophic equipment failures. Furthermore, depending on the

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[149] Robinson and Dolbear, "Commercial Hydrotreating and Hydrocracking. *In* Hydroprocessing of heavy oils and residua," 2007. Ancheyta and Speight, eds. CRC Press, Taylor and Francis Group: Boca Raton, FL, pp. 308, 309.

[150] The Project could consume 2,220–3,020 standard cubic feet of H_2 per barrel of drop-in biodiesel feed processed. Karras, 2021a. *Changing Hydrocarbons Midstream* (Attached hereto). Operating data from U.S. petroleum refineries during 1999–2008 show that nationwide petroleum refinery usage of hydrogen production plant capacity averaged 272 cubic feet of H_2 per barrel crude processed. Karras, 2010. *Environ. Sci. Technol.* 44(24): 9584 and Supporting Information. (*See* data in Supporting Information Table S-1.) https://pubs.acs.org/doi/10.1021/es1019965.

[151] van Dyk et al., 2019. *Biofuels Bioproducts & Biorefining* 13: 760–775. *See* p. 765 ("exothermic reaction, with heat release proportional to the consumption of hydrogen"). https://onlinelibrary.wiley.com/doi/10.1002/bbb.1974.

[152] Flaring causal analyses, various dates. Reports required by Bay Area Air Quality Management District Regulation 12, Rule 12, including reports posted at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports and reports for incidents predating those posted at that link.

[153] Chan, 2020. www.burnsmcd.com/insightsnews/tech/converting-petroleum-refinery-for-renewable-diesel. *See* p. 2 ("emergency depressurization" capacity required).

[154] van Dyk et al., 2019 as cited above at 765 ("heat release proportional to the consumption of hydrogen"); and Chan, 2020 as cited above at 2 ("significantly more exothermic than petroleum diesel desulfurization reactions").

contaminants and processing byproducts of the particular Project feedstock chosen, it could create new damage mechanism hazards or exacerbate existing hazards to a greater degree. As Chan notes:

> Feedstock that is high in free fatty acids, for example, has the potential to create a corrosive environment. Another special consideration for renewable feedstocks is the potential for polymerization ... which causes gumming and fouling in the equipment ... hydrogen could make the equipment susceptible to high temperature hydrogen attack ... [and drop-in biodiesel process] reactions produce water and carbon dioxide in much larger quantities than petroleum hydrotreaters, creating potential carbonic acid corrosion concerns downstream of the reactor.[155]

C. Significant Hazard Impacts Appear Likely Based on Both Site-Specific and Global Evidence

Site-specific evidence shows that despite current safeguards, hydrogen-related hazards frequently contributed to significant flaring incidents, even before the worsening of hydro-conversion intensity and hydrogen-related process safety hazards which could result from the Project. Causal analysis reports for significant flaring from unplanned incidents indicate that at least 52 hydrogen-related process safety hazard incidents occurred at the Refinery from January 2010 until it closed on 28 April 2020.[156] This is a conservative estimate, since incidents can cause significant impacts without environmentally significant flaring, but still represents, on average, another hydrogen-related hazard incident at the Refinery every 70 days. Moreover, considering the Refinery and Marathon Martinez refinery flare data together, sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these reported incidents.[157] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[158] In other words, incidents escalated to refinery-level systems involving multiple plants frequently—a foreseeable consequence since 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 at the Refinery.[159]

Catastrophic consequences of hydrogen-related hazards are foreseeable based on industry-wide reports as well as site-specific evidence. For example:

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[155] Chan, 2020 as cited above at 3.

[156] Flaring causal analyses, various dates. Reports required by Bay Area Air Quality Management District Regulation 12, Rule 12, including reports posted at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports and reports for incidents predating those posted at that link.

[157] Flaring causal analyses as cited above. Hydro-conversion includes hydrotreating and hydrocracking.

[158] *Id.*

[159] Flaring causal analyses as cited above. *See* reports for incidents starting 13 May 2010, 17 February 2011 and 17 April 2015.

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire;[160]
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage;[161]
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor;[162]
- A 2015 hydrogen conduit explosion throws workers against a refinery structure;[163]
- Fifteen workers die, and 180 others are injured, in a series of 2005 explosions when hydrocarbons flood a distillation tower during an isomerization unit restart;[164]
- 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;[165]
- A worker dies, 46 others are injured, and the surrounding community is forced to 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;[166]
- 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;[167]
- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on nearby Richmond refinery equipment;[168]
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.[169]

Since the Project's new feedstock and process system are thus known to worsen the underlying conditions that can become (and have become) root causes of hazardous incidents, the DEIR should have disclosed, thoroughly evaluated, and mitigated these risks. The DEIR should have analyzed, *inter alia,* the impact of the proposed new feedstock and production process on worker safety, community safety, and upset frequency and impacts (including increased flaring).

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[160] Process Safety Integrity, *Refining incidents;* https://processsafetyintegrity.com/incidents/industry/refining ; *see* Bayernoil Refinery Explosion, January 2018.
[161] Process Safety Integrity as cited above; *see* Syncrude Fort McMurray Refinery Fire, March 2017.
[162] Process Safety Integrity as cited above; *see* Sir Refinery Fire, January 2017.
[163] Process Safety Integrity as cited above; *see* Petrobras (RLAM) Explosion, January 2015.
[164] Process Safety Integrity as cited above; *see* BP Texas City Refinery Explosion, March 2005.
[165] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Explosion, March 1999.
[166] Process Safety Integrity as cited above; *see* Tosco Avon (Hydrocracker) Explosion, January 1997.
[167] Process Safety Integrity as cited above; *see* Carson Refinery Explosion, October 1992.
[168] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Fire, April 1989.
[169] Process Safety Integrity as cited above; *see* BP (Grangemouth) Hydrocracker Explosion, March 1987.

D. Process Operation Mitigation Measures Can Reduce but Not Eliminate Process Safety Hazard Impacts

There are procedures to control the reaction heat, pressure – including through process operation measures such as quenching between catalyst beds in the reactor and careful control of how hot the reactor components get, how much hydrogen is added, how much feed is added, and how long the materials remain in the reactor, preventing hot spots from forming inside of it, and intensive monitoring for equipment damage and catalyst fouling. These measures should have been considered in the DEIR as mitigation for process safety impacts, but were not.

However, such analysis would also need to account for the fact that these measures are imperfect at best, and rely on both detailed understanding of complex process chemistry and monitoring of conditions in multiple parts of the process environment. Both those conditions are difficult to attain in current petroleum processing, and even more difficult with new feedstocks with which there is less current knowledge about the complex reactions and how to monitor them when the operator cannot "see" into the reactor very well during actual operation; and cannot meet production objectives if production is repeatedly shut down in order to do so.

In fact, the measures described above are "procedural safeguards,"[170] the least effective type of safety measure in the "Hierarchy of Hazard Control"[171] set forth in California process safety management policy for petroleum refineries.[172] It would also in principle be possible to add automated shutdown control logic systems to these procedural safeguards before it closed the refinery, as Marathon proposes to do in its similar biofuel conversion, but these are "active safeguards,"[173] the next least effect type of safety measure in the Hierarchy of Hazard Control. Similarly, it would be possible to replace some of the vessel and piping linings of its old Refinery equipment, which would be repurposed for the Project, with more corrosion-resistant metallurgy—an added layer of protection in those parts of the biorefinery where this proposal might be implemented, and a tacit admission that potential hazards of processing its proposed feedstock are a real concern. This type of measure is a "passive safeguard,"[174] the next least effective type of measure in the Hierarchy of Hazard Control, after procedural and active safeguards. Both of these measures, and others like them, should have been considered; but their effectiveness is limited.

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[170] Procedural safeguards are policies, operating procedures, training, administrative checks, emergency response and other management approaches used to prevent incidents or to minimize the effects of an incident. Examples include hot work procedures and emergency response procedures. California Code of Regulations (CCR) § 5189.1 (c).

[171] This Hierarchy of Hazard Control ranks hazard prevention and control measures "from most effective to least effective [as:] First Order Inherent Safety, Second Order Inherent Safety, and passive, active and procedural protection layers." CCR § 5189.1 (c).

[172] We note that to the extent this state policy, the County Industrial Safety Ordinance, or both may be deemed unenforceable with respect to biorefineries which do not process petroleum, that only further emphasizes the need for full analysis of Project hazard impacts and measures to lessen or avoid them in the DEIR.

[173] Active safeguards are controls, alarms, safety instrumented systems and mitigation systems that are used to detect and respond to deviations from normal process operations; for example, a pump that is shut off by a high-level switch. CCR § 5189.1 (c).

[174] See CCR § 5189.1 (c).

Importantly, and perhaps most telling, Phillips 66 proposes to repurpose and continue to use the flare system of its closed refinery for this Project. DEIR at 3-29. Rather than eliminating underlying causes of safety hazard incidents or otherwise preventing them, refinery flare systems are designed to be used in procedures that minimize the effects of such incidents.[175] This is a procedural safeguard, again the least effective type of safety measure.[176] The flares would partially mitigate incidents that, in fact, are expected to occur if the Project is implemented, but flaring itself causes acute exposure hazards. And as incidents caused by underlying hazards that have not been eliminated continue to recur, they can eventually escalate to result in catastrophic consequences. In essence, the Project description itself demonstrates the need to address process hazards that site-specific data show to be potentially significant and the DEIR fails to address.

E. The DEIR Should Have Evaluated the Potential for Deferred Mitigation of Process Hazards

The DEIR should have considered available means to address the Project design, and impose appropriate conditions and limitations, to mitigate process safety hazards. Examples of potential mitigation measures that should have been considered (in addition to the process measures referenced above of limited effectiveness) include the following:

- *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 and some HEFA feedstocks increase process hydrogen demand significantly more than other others, 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, 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.

Commenters are not necessarily recommending these particular measures. However, these and any other options for mitigating process hazards through design or other conditions should have been considered, and were not.

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[175] *See* BAAQMD regulations, § 12-12-301. Bay Area Air Quality Management District: San Francisco, CA.

[176] *See* Procedural Measure and Hierarchy of Hazard Control definitions under CCR § 5189.1 (c) in the notes above.

VI. THE DEIR INADEQUATELY DISCLOSES AND ADDRESSES PROJECT GREENHOUSE GAS AND CLIMATE IMPACTS

The DEIR analysis of greenhouse gas (GHG) emissions and climate impacts suffers from the same baseline-related flaw as numerous other subjects in the document, *i.e.*, it determines emission impacts from a baseline of continuing crude oil production as opposed to actual current shutdown conditions. Based on the flaw alone, the DEIR analysis of GHG emissions impacts must be revised to incorporate the correct baseline.

However, even aside from this major flaw, the DEIR's analysis of GHG and climate impacts is deficient. The document identifies as significance criteria both (1) whether the Project would generate significant GHG emissions, and (2) whether it would "conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of GHG." DEIR at 3.8-19. The DEIR fails to adequately evaluate the first significance criterion because it fails to account for potentially increased GHG emissions associated with the processing of varying biofuel feedstocks. It also fails to adequately evaluate the second significance criterion, because it ignores the potential downstream impact of a significant increase in biofuel production on state and local climate goals. As noted in the Scoping Comments but not addressed in the DEIR at all, those goals include an increase in use of battery electric vehicles to electrify the state's transportation sector and decrease use of combustion fuels[177]; as well as a "Diesel Free by '33" pledge promoted by BAAQMD and entered into by Contra Costa County, which commits the County to, *inter alia,* "[u]se policies and incentives that assist the private sector as it moves to diesel-free fleets and buildings."[178] The DEIR further fails to identify the significant shifting of GHG emissions from California to other jurisdictions that would likely occur as a consequence of the Project.

The following sections address the various potential conflicts between the Project and state and local plans, policies, and regulations adopted for the purpose of reducing GHG emissions that render the Project's impacts potentially significant, but which the DEIR nonetheless failed to consider.

A. The DEIR Air Impacts Analysis Fails to Take Into Account Varying GHG Emissions from Different Feedstocks and Crude Slates

The following subsections discuss ways in which Project GHG emissions vary widely with feedstock choice, as well as reasons why those emissions may increase rather than decrease over the comparable crude oil refining emissions.

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[177] Executive Order N-79-20 dated September 23, 2020, *available at* https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-text.pdf.

[178] *See* https://dieselfree33.baaqmd.gov/ (landing page), https://dieselfree33.baaqmd.gov/statement-of-purpose (text of the pledge), https://dieselfree33.baaqmd.gov/signatories (signatories).

1. Processing Biofuel Feedstock Instead of Crude Oil Can Increase Carbon Emission Intensity of the Refining Process

The DEIR did not address the fact that the process of refining biofuel feedstocks is significantly more carbon intense than crude oil refining. This increased carbon intensity has primarily to do with the fact that HEFA feedstocks have vastly more oxygen in them than crude oil – and hence require more hydrogen production to remove that oxygen. The oxygen content of the various proposed Project feedstocks is approximately 11 wt. % (Table 1), compared with refining petroleum crude, which has virtually no oxygen. Oxygen would be forced out of the HEFA feedstock molecules by bonding them with hydrogen to make water (H_2O), which then leaves the hydrocarbon stream. This process consumes vast amounts of hydrogen, which must be manufactured in amounts that processing requires. The deoxygenation process chemistry further boosts HEFA process hydrogen demand by requiring saturation of carbon double bonds.

These "hydrodeoxygenation" (HDO) reactions are a fundamental change from petroleum refining chemistry. This new chemistry is the main reason why—despite the "renewable" label Phillips 66 has chosen—its biorefinery could emit more carbon per barrel processed than petroleum refining. That increase in the carbon intensity of fuels processing would be directly connected to the proposed change in feedstock.

Table 1. Impact of Project Feedstock Choice on CO_2 Emissions from Hydrogen Production for Phillips 66 Project Targeting Diesel: Estimates based on readily available data.

t/y: metric tons/year **kg:** kilogram **b:** barrel, 42 U.S. gallons

	Feedstock			Difference	
	Tallow	**Soy oil**	**Fish oil**	**Soy oil–tallow**	**Fish oil–tallow**
Processing characteristics [a]					
Oxygen content (wt. %)	11.8	11.5	11.5	– 0.3	– 0.3
H_2 for saturation (kg H_2/b)	0.60	1.58	2.08	+ 0.98	+ 1.48
H_2 for deoxygenation (kg H_2/b)	4.11	4.11	4.13	0.00	+ 0.02
Other H_2 consumption (kg H_2/b)	0.26	0.26	0.26	0.00	0.00
Process H_2 demand (kg H_2/b)	4.97	5.95	6.47	0.98	1.50
Hydrogen plant emission factor					
HEFA mixed feed (g CO_2/g H_2) [a]	9.82	9.82	9.82		
Methane feed (g CO_2/g H_2) [b]	9.15	9.15	9.15		
Hydrogen plant CO_2 emitted					
HEFA mixed feed (t/y) [a]	1,420,000	1,710,000	1,850,000	290,000	430,000
Methane feed (t/y) [b]	1,330,000	1,590,000	1,730,000	260,000	400,000

a. Data from HEFA feedstock-specific composition analysis based on multiple feed measurements, process analysis for HEFA hydro-conversion process hydrogen demand, and emission factor based on median SF Bay Area hydrogen plant verified design performance and typical expected HEFA process hydrogen plant feed mix. From Karras, 2021b. *See* also Karras, 2021a.
b. Data from Sun et al. for median California merchant steam methane reforming hydrogen plant performance. Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 Note that these steam methane reforming plant data are shown for context. Steam reforming of HEFA byproduct propane can be expected to increase direct emissions from the steam reforming and shift reactions. Karras, 2021a. Mass emissions based on 80,000 b/d project capacity. Fish oil values shown are based on Menhaden.

Hydrogen must be added to bond with oxygen in HEFA feeds and thereby remove the oxygen in them, and to bond with carbon atoms in fatty acids in order to facilitate this deoxygenation of the feed carbon chains converted to hydrocarbons. This increases the hydrogen needed for the proposed HEFA[179] processing over and above the hydrogen that was needed for the crude refining that formerly took place at the Refinery. Deoxygenation is the major driver of this high process hydrogen demand, but HEFA feeds are consistently high in hydrogen, while some have more carbon double bonds that must be "saturated" first, and thus higher saturation hydrogen demand, than other feeds. Table 1 shows both of these things.

The DEIR – to the extent it considers past petroleum refining emissions in its analysis – must consider the air emissions impact of increased hydrogen use. Oxygen-rich HEFA feedstocks force increased hydrogen production – and attendant hydrogen production emissions -- by a proportional amount. These emissions are significant, because Phillips 66 proposes to make that hydrogen in existing fossil fuel hydrogen plants. This hydrogen steam reforming technology is extremely carbon intensive. It burns a lot of fuel to make superheated high-pressure steam mixed with hydrocarbons at temperatures up to 1,400–1,900 ºF. And on top of those combustion emissions, its "reforming" and "shift" reactions produce hydrogen by taking it from the carbon in its hydrocarbon feed. That carbon then bonds with oxygen to form carbon dioxide (CO_2) that emits as well. Making the vast amounts of hydrogen needed for Project processing could cause CO_2 emissions from Project hydrogen plants alone to exceed a million tons each year.

The resulting carbon intensity difference between crude oil refining and biofuel refining is striking. CO_2 emissions from U.S. petroleum refineries averaged 41.8 kg per barrel crude feed from 2015-2017 (the most recent data available).[1] By contrast, HEFA production emits 55-80 kg per barrel biomass feed associated with increased hydrogen production *alone* – such exceeding petroleum refining carbon intensity by 32-91 percent. Beyond the hydrogen-production driver of increased carbon intensity, additional CO_2 would emit from fuel combustion for energy to heat and pressure up HEFA hydro-conversion reactors, precondition and pump their feeds, and distill, then blend their hydrocarbon products.[180]

2. GHG Emissions Impacts Vary With Different Potential Feedstocks

Crucially, feeds that the Project targets, such as tallow and SBO - and some that it does not but may nonetheless potentially use such as fish oil - require hydrogen for processing to significantly different degrees. Table 1 shows this difference in weight percent, a common measure of oil feed composition. The 0.98 kilograms per barrel feed difference in hydrogen saturation between soy oil and tallow is why processing soy oil requires that much more hydrogen per barrel of Project feed (0.98 kg/b). Table 1. Similarly, the 1.48 kg/b difference

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[179] As noted in previous sections, the type of drop-in biofuel technology proposed is called "Hydrotreating Esters and Fatty Acids" (HEFA).

[180] Karras, 2021. Unverified potential to emit calculations provided by one refiner[1] suggest that these factors could add ~21 kg/b to the 55-80 kg/b from HEFA steam reforming. This ~76–101 kg/b HEFA processing total would exceed the 41.8 kg/b carbon intensity of the average U.S. petroleum refinery by ~82-142 percent. Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing. *See* supporting material for Karras, 2021a

between fish oil and tallow requires 1.48 more kilograms of hydrogen per barrel to make so-called "renewable" diesel from fish oil than to make it from tallow. *Id.*

Thus, feedstock choice would drive the magnitude of carbon emissions to a significant degree. *Id.* For instance, to the extent Phillips 66 runs SBO, Project hydrogen plants could emit approximately 290,000 metric tons more CO_2 each year than if it runs tallow. *Id.* This 290,000 t/y excess would exceed the emissions significance threshold for greenhouse gases in the DEIR, 10,000 metric tons/year CO_2e,[181] by *28 times.* And if Phillips 66 were to run fish oil, another potential feedstock not specifically targeted but also not excluded, the estimates in Table 1 suggest that Project hydrogen plants could emit 430,000 tons/year more CO_2 than if it runs tallow, or *42 times* that significance threshold. Thus, available evidence indicates that the choice among Project feedstocks itself could result in significant emission impacts. Therefore, emissions from each potential feedstock should be estimated in the EIR.

The CO_2 emissions estimates in Table 1 are relatively robust and conservative, though the lack of project-specific details disclosed in the DEIR described in Section II still raises questions a revised County analysis should answer. The carbon intensity estimate for HEFA hydrogen production is remarkably close that for steam methane reforming, as expected since hydrocarbon byproducts of HEFA refining, when mixed with methane in project hydrogen plants, would form more CO_2 per pound of hydrogen produced than making that hydrogen from methane alone. The estimate may indeed turn out to be too low, given the variability in hydrogen plant emissions generally,[182] and the tendency of older plant designs to be less efficient and higher emitting. The DEIR should have evaluated this part of Project processing emissions using data for the Refinery's hydrogen plants that would be used by the Project; and Phillips 66 should have been required to provide detailed data on those plants to support this estimate.

Feedstock choices can impact other greenhouse gases as well through varying hydrogen demand. In addition to the potential for feedstock-driven increases in emissions of CO_2, the proposed hydrogen production would emit methane, a potent greenhouse gas that also contributes to ozone formation, via "fugitive" leaks or vents. Aerial measurements and investigations triggered by those recent measurements suggest, further, that methane emissions from hydrogen production have been underestimated dramatically.[183]

Crucially as well, making a different product slate can increase GHG emissions from the same feedstock. This is why, for example, the California Air Resources Board estimates a different carbon intensity for refining gasoline, diesel, or jet fuel from the same crude feed. Targeting jet fuel instead of drop-in diesel production from the same vegetable oil or animal fat

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[181] *See* Chevron Refinery Modernization Project EIR. SCH # 2001062042. 2014. City of Richmond, CA. *See* esp. pp. 4.8-11, 4.8-12, 4.8-18, 4.8-19, 4.8-24, 4.8-27, 4.8-28, 4.8-38, 4.8-70 (10,000 metric tons/yr significance threshold).

[182] Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 .

[183] Guha et al., 2020. *Environ. Sci. Technol.* 54: 9254–9264 and Supporting Information. https://dx.doi.org/10.1021/acs.est.0c01212

feed could increase processing emissions significantly.[184] Thus, since differences between potential Project feedstocks and Project products could each increase emissions independently or in combination, the DEIR should have estimated emissions for each potential Project feedstock for product slates targeting both diesel and jet fuel.

Thus, processing emissions of GHGs should have been estimated in the DEIR for each potential Project feedstock and product slate, or range of product slates, proposed to be manufactured from it, including a reasonable worst case scenario.

B. The DEIR Failed to Consider the Impact of Biofuel Oversupply on Climate Goals

California has implemented a series of legislative and executive actions to reduce greenhouse gas emissions (GHGs) and address climate change. Two flagship bills were aimed at directly reducing GHG emissions economy wide: AB32, which called for reductions in GHG emissions to 1990 levels by 2020;[185] and SB32, which calls for reductions in GHG emissions to 40% below 1990 levels by 2030.[186] Following this, California Executive Order S-3-05 calls for a reduction in GHG emissions to 80% below 1990 levels by 2050.[187] Finally, Executive Order B-55-18 calls for the state "to achieve carbon neutrality as soon as possible, but no later than 2045, and achieve and maintain net negative emissions thereafter."[188]

In order to meet these legislative and executive imperatives, numerous goals have been set to directly target the state's GHG emissions just in the last two years: for 100% of light-duty vehicle (LDV) sales to be zero-emission vehicles (ZEVs) by 2035; for 100% of medium- and heavy-duty vehicle (MDV and HDV) sales to be ZEVs by 2045;[189] for a ban on hydraulic fracturing by 2024; and for an end to all state oil drilling by 2045.

Such goals, both the ZEV sales mandates that target liquid combustion fuel demand and the proposed bans on petroleum extraction that target supply, point to the need to transition from petroleum-based transportation fuels to sustainable alternatives. The DEIR frames biofuels as a means to reduce reliance on "traditional" transportation fuels, the original purpose of the LCFS. DEIR at 3.8-13. It insists that this Project is a necessary fulfillment of the 2017 Scoping Plan and LCFS. DEIR at 3.8-22. However, the 2017 Scoping Plan targets do not distinguish between fuel technologies (e.g. HEFA v. Fischer-Tropsch) or feedstock (crop-based lipid v. cellulosic). Yet

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[184] Seber et al., 2014. *Biomass and Bioenergy* 67: 108–118. http://dx.doi.org/10.1016/j.biombioe.2014.04.024. *See* also Karatzos et al., 2014. Report T39-T1, IEA Bioenergy Task 39. IEA ISBN: 978-1-910154-07-6. (*See* esp. p. 57; extra processing and hydrogen required for jet fuel over diesel.) https://task39.sites.olt.ubc.ca/files/2014/01/Task-39-Drop-in-Biofuels-Report-FINAL-2-Oct-2014-ecopy.pdf *See also* Karras, 2021b.

[185] Legislative Information, AB-32, California Global Warming Solutions Act of 2006 (Accessed November 29, 2021), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html

[186] Legislative Information, SB-32 California Global Warming Solutions Act of 2006: Emissions Limit, (Accessed November 29, 2021), from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32

[187] Executive Order S-3-05. Executive Department, State of California, Arnold Schwarzenegger, Governor, State of California; https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/5129-5130.pdf.

[188] Executive Order B-55-18. Executive Department, State of California, Edmund Brown, Governor, State of California; https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

[189] Executive Order N-79-20. Executive Department, State of California, Gavin Newsom, Governor, State of California; https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

feedstock and technology make a significant difference on GHG emissions. If anything, the environmental analysis of the 2017 Scoping Plan, like that of the LCFS, predicted that crop-based biofuels would need additional Project-specific environmental analysis and mitigation.[190] This cursory invocation of the LCFS fails to address the problem of biofuel volume: too much biofuel production risks interfering with the ZEV goals most recently established by Governor Newsom. The overproduction problem is related in part to the higher carbon intensity of biofuel refining as compared to oil refining, and in part to its volume effects on the types, amounts, and locations of both zero-emission and petroleum fuels production and use. This problem of overproduction is not addressed in the LCFS. The LCFS, designed to establish incremental per-barrel impacts, is not set up to address the macro impact of overproduction or overuse of combustion fuels on California climate goals.

In numerous state-sponsored studies, there is acknowledgment of the need to limit our biofuel dependence. These studies consistently demonstrate that California's climate goals require a dramatic reduction in the use of *all* combustion fuels in the state's transportation sector, not just petroleum-based fuels. They indicate the need for biofuel use to remain limited. Specifically, pathway scenarios developed by Mahone et al. for the California Energy Commission (CEC),[191] Air Resources Board (CARB)[192] and Public Utilities Commission,[193] Austin et al. for the University of California,[194] and Reed et al. for UC Irvine and the CEC[58] add semi-quantitative benchmarks to the 2050 emission target for assessing refinery conversions to biofuels. They join other work in showing the need to decarbonize electricity and electrify

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[190] California Air Resources Board. Appendix F: Final Environmental Analysis for The Strategy for Achieving California's 2030 Greenhouse Gas Target, pp. 56, https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2030sp_appf_finalea.pdf.

[191] Mahone et al., 2018. *Deep Decarbonization in a High Renewables Future: Updated results from the California PATHWAYS Model;* Report CEC-500-2018-012. Contract No. EPC-14-069. Prepared for California Energy Commission. Final Project Report. Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf

[192] Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf

[193] Mahone et al., 2020b. *Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States;* Energy and Environmental Economics, Inc.: San Francisco, CA. Report prepared for ACES, a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC. Submitted to the California Public Utilities Commission June 2020. https://www.ethree.com/?s=hydrogen+opportunities+in+a+low-carbon+future

[194] Austin et al., 2021. *Driving California's Transportation Emissions to Zero;* Report No.: UC-ITS-2020-65. Institute of Transportation Studies, University of California. DOI: 10.7922/G2MC8X9X. https://escholarship.org/uc/item/3np3p2t0

transportation.[195] Their work evaluates a range of paths to state climate goals,[196] analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,[197] and addresses potential biomass fuel chain effects on climate pathways.[198]

Mahone's study prepared for CARB explored three scenarios for achieving carbon neutrality by 2045.[199] The scenarios include "The Zero Carbon Energy scenario" which would achieve zero-fossil fuel emission by 2045 with minimal use of carbon dioxide removal (CDR) strategies, "The High CDR scenario" which would achieve an 80% reduction in gross GHG emissions by 2045 but relies heavily on CDR, and "The Balanced scenario" which serves as a midpoint between the other two scenarios. Notably, all three of these pathways cut liquid petroleum fuel use dramatically, with biofuels replacing only a portion of that petroleum. Chart 3 illustrates the transportation fuel mix for these three pathways:

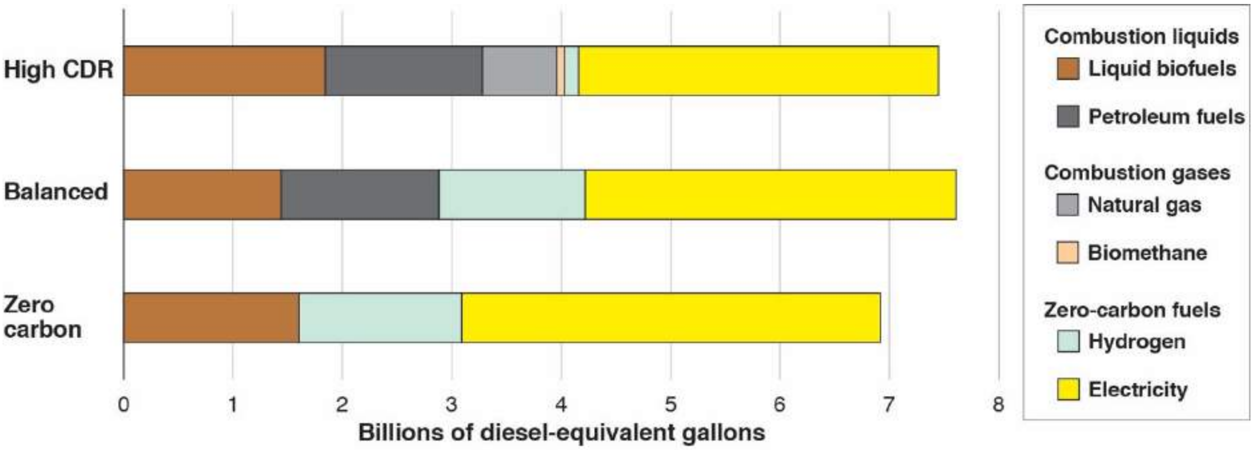

Chart 3: California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.
Adapted from Figure 8 in Mahone et al. (2020).[200] Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).

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[195] Mahone et al 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2021; Reed et al., 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California;* Final Project Report CEC-600-2020-002. Prepared for the California Energy Commission by U.C. Irvine Advanced Power and Energy Program. Clean Transportation Program, California Energy Commission: Sacramento, CA. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292; Williams et al., 2012. The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. *Science* 53–59. https://doi.org/DOI: 10.1126/science.1208365; Williams et al., 2015. Pathways to Deep Decarbonization in the United States; The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute of Sustainable Development and International Relations. Revision with technical supp. Energy and Environmental Economics, Inc., in collaboration with Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory. https://usddpp.org/downloads/2014-technical-report.pdf; Williams et al., 2021. Carbon-Neutral Pathways for the United States. *AGU Advances* 2, e2020AV000284. https://doi.org/10.1029/2020AV000284.

[196] Mahone et al. 2020a.

[197] Mahone et al. 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2020; Reed et al. 2020.

[198] Mahone et al. 2018; Mahone et al. 2020a; Reed et al. 2020.

[199] Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf

[200] Mahone et al., 2020.

Total liquid hydrocarbon combustion fuels for transportation in 2045, including both petroleum and biofuels, range among the pathways from approximately 1.6 to 3.3 billion gallons/year, with the lower end of the range corresponding to "The Zero Carbon Energy scenario," and the higher end of the range corresponding to "The High CDR scenario." The range represents roughly 9% to 18% of statewide annual petroleum transportation fuels use from 2013-2017, indicating the planned reduction in liquid hydrocarbon combustion fuels reliance by 2045.[201] Liquid biofuels account for approximately 1.4 to 1.8 billion gallons/year by 2045, which is roughly 40% to 100% of liquid transportation fuels use in 2045 depending on scenario, with 100% corresponding to "The Zero Carbon Energy Scenario." So, in "The Zero Carbon Energy Scenario," the most ambitious of the three, though biofuels constitute the entirety of liquid transportation fuel use, liquid transportation fuel use overall is greatly reduced.

These State-commissioned studies suggest limits on the use of biofuels by specifically excluding or limiting the production of HEFA ("lipid") fuels. PATHWAYS, the primary modeling tool for the AB 32 Scoping Plan, now run a biofuels module to determine a least-cost portfolio of the biofuel products ultimately produced (e.g. liquid biofuel, biomethane, etc.) based on biomass availability.[202] Mahone et al. chose to exclude purpose-grown crops because of its harmful environmental impacts and climate risks and further limitied the biomass used to in-state production in addition to California's population-weighted share of total national waste biomass supply.[203] Consequently, it was assumed that all California biofuel feedstock should be cellulosic residues as opposed to the typical vegetable oil and animal fat HEFA feedstocks. A study by Austin et al. meanwhile, in considering pathways to reduce California's transportation emissions, placed a cap on HEFA jet fuel and diesel use to a maximum of 0.5–0.6 and 0.8–0.9 billion gallons/year, respectively.[204] Yet new in-state HEFA distillate (diesel and jet fuel) production proposed statewide, with a large share to come from the Refinery, would total approximately 2.1 billion gallons/year when fully operational.[205] If fully implemented, HEFA

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[201] Mahone et al., 2020.

[202] E3 introduced a new biofuels module in the model that, unlike previous iterations of the PATHWAYS model, endogenously selects least-cost biofuel portfolios given the assumed available biomass. Mahone et al., 2020, footnote 2 at 19-20.

[203] *See e.g.,* Mahone et al., 2018. *Deep Decarbonization in a High Renewables Future: Updated results from the California PATHWAYS Model;* Report CEC-500-2018-012. Contract No. EPC-14-069. Prepared for California Energy Commission. Final Project Report. Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf ("most scenarios apply this more restrictive biomass screen to avoid the risk that the cultivation of biomass for biofuels could result in increased GHG emissions from natural or working lands.", pp. 10).

[204] Austin et al., 2021. *Driving California's Transportation Emissions to Zero;* Report No.: UC-ITS-2020-65. Institute of Transportation Studies, University of California. DOI: 10.7922/G2MC8X9X. https://escholarship.org/uc/item/3np3p2t0

[205] Supporting Material Appendix for *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, www.energy-re-source.com; *Application for Authority to Construct Permit and Title V Operating Permit Revision for Rodeo Renewed Project: Phillips 66 Company San Francisco Refinery (District Plant No. 21359 and Title V Facility # A0016);* Prepared for Phillips 66 by Ramboll US Consulting, San Francisco, CA. May 2021; *Initial Study for: Tesoro Refining & Marketing Company LLC—Marathon Martinez Refinery Renewable Fuels Project;* received by Contra Costa County Dept. of Conservation and Development 1 Oct 2020; *April 28, 2020 Flare Event Causal Analysis; Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758;* report dated 29 June, 2020 submitted by Marathon to the

fuel production could exceed caps of 0.0–1.5 billion gallons/year prescribed by the aforementioned state climate pathways.

In both studies, the reason given for limiting HEFA fuel reliance is the difficult-to-predict land use emissions associated with HEFA feedstocks. As discussed in the previous subsection, HEFA fuels can be associated with significant greenhouse gas emissions, on par with emissions from conventional oil production in some cases. Additionally, the refining emissions associated with HEFA production impact HEFA fuel cycle emissions—an impact that the DEIR did not consider. The carbon intensity of HEFA refining is roughly 180% to 240% of the carbon intensity of refining at the average U.S. crude refinery.[206] Those refining emission increments would then add to the potentially larger effect of overuse of biofuels instead of ZEVs.

Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing when climate goals demand that carbon intensities decrease. That could contribute significantly to emissions in excess of the needed climate protection and state policy trajectory. California's goal of 2050[207] goal of emissions 80% below 1990 levels by 2050 is equivalent to 86.2 million tons (MT) CO_2eq emissions in 2050. Given future projections of transportation fuel demand, HEFA diesel and jet fuel CO_2eq emissions could reach 66.9 Mt per year in 2050. [208] Adding in emissions from remaining petroleum fuel production could push emissions to 91 Mt in 2050.[209] Total 2050 emissions could thus be larger than the state target.

Similarly, the goal of carbon neutrality by 2045 either requires no emissions in 2045, or for emissions that do occur to be offset by negative emissions technologies such as carbon capture and storage (CCS). Relying on HEFA fuels in the future means that there will be emissions, so without CCS, carbon neutrality will not be reached. Yet carbon capture and storage has not been proven at scale, so it cannot be relied upon to offset HEFA fuel-associated emissions to meet mid-century emissions goals. Existing CCS facilities capture less than 1 percent of global carbon emissions, while CCS pilot projects have repeatedly overpromised and underdelivered in providing meaningful emissions reductions.[210] Therefore, repurposing idled petroleum refinery assets for HEFA biofuels will cause us to miss key state climate benchmarks.

Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports; *Paramount Petroleum, AltAir Renewable Fuels Project Initial Study;* submitted to City of Paramount Planning Division, 16400 Colorado Ave., Paramount, CA. Prepared by MRS Environmental, 1306 Santa Barbara St., Santa Barbara, CA; Brelsford, R. Global Clean Energy lets contract for Bakersfield refinery conversion project. *Oil & Gas Journal.* 2020**.** Jan. 9, 2020.

[206] The difference between the upper and lower bounds of that range is driven by the (here undisclosed in the DEIR) difference between choices by the refinery to be made by Phillips 66 among HEFA feeds, and between diesel versus jet fuel production targets. Karras, 2021a.

[207] The 80% is required as a direct emission reduction, not a net reduction that may take into consideration negative emission measures such as CCS. Executive Order S-3-05.

[208] Karras, 2021a. For context, HEFA hydrogen steam reforming emissions alone could account for some 20 Mt/yr or more of this projected 66.9 Mt/yr.

[209] *Id.*

[210] Center for International Environmental Law, Confronting the Myth of Carbon-Free Fossil Fuels, Why Carbon Capture Is Not a Climate Solution (2021), https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf.

The DEIR's conclusion that the Project is consistent with state climate directives without the analysis described above is a fatal flaw in that conclusion. A recirculated DEIR must evaluate all of the pathway studies and analysis described in this section, and make a determination regarding the Project's consistency with the state's climate law and policy based on all of the factors described in this comment.

C. The DEIR Failed to Consider a Significant Potential GHG Emission Shifting Impact Likely to Result from the Project

Despite claims that biofuels have a carbon benefit, the data thus far show that increased production of the particular type of biofuel that the Project proposes has actually had the effect of *increasing* total GHG emissions, by simply pushing them overseas. Instead of replacing fossil fuels, adding renewable diesel to the liquid combustion fuel chain in California resulted in refiners increasing exports of petroleum distillates burned elsewhere, causing a worldwide net increase in GHG emissions. The DEIR improperly concludes the Project would decrease net GHG emissions[211] without disclosing this emission-shifting (leakage) effect. A series of errors and omissions in the DEIR further obscures causal factors in the emission shifting by which the Project would cause and contribute to this significant potential impact.

1. The DEIR Fails to Disclose or Evaluate Available Data Which Contradict Its Conclusion That the Project Would Result in a Net Decrease in GHG Emissions.

State climate 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."[212] However, the DEIR fails to 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[213] and total distillates—petroleum distillates and diesel biofuels—burned in California.[214] Had the DEIR evaluated these data the County could have found that its conclusion regarding net GHG emissions resulting from the Project was wholly unsupported.

As shown in Chart 4, petroleum distillate fuels refining for export continued to expand in California in the last two decades even as biofuel production ramped up in recent years. It is clear from this data that renewable diesel production during those decades -- originally expected to replace fossil fuels – actually merely 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.[215] [216]

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[211] "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).

[212] CCR §§ 38505 (j), 38562 (b) (8).

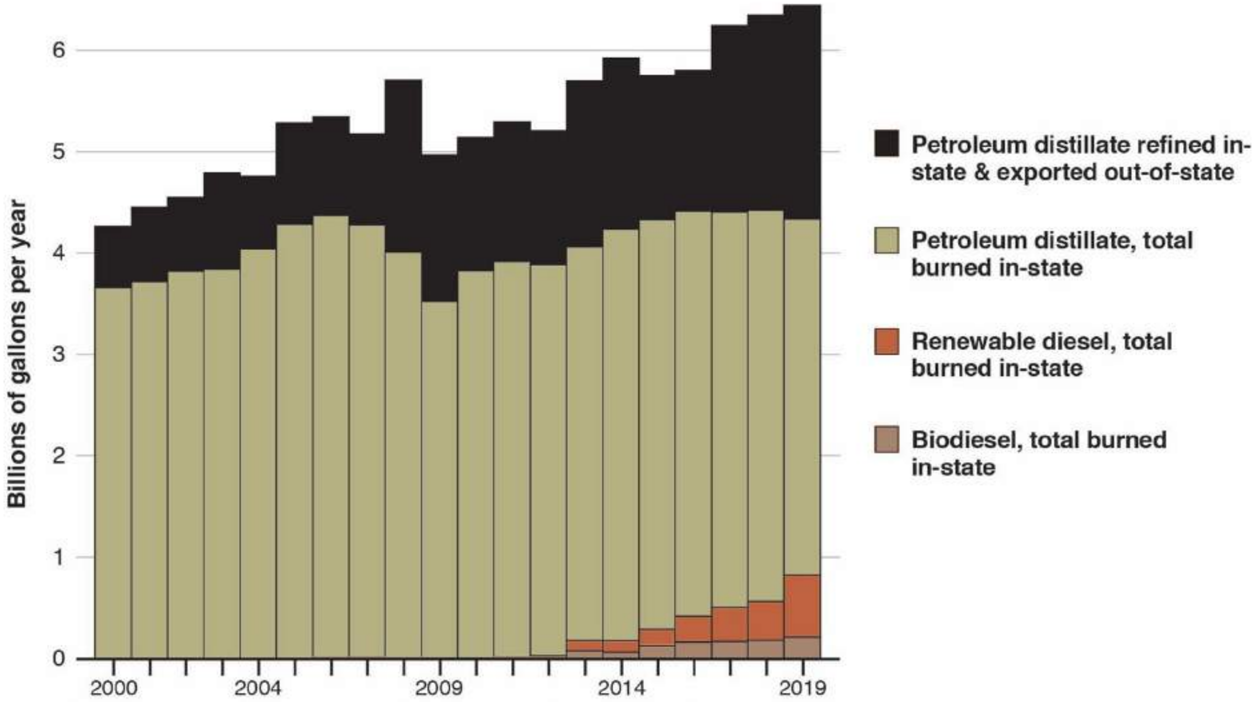
[213] CEC, Fuel Watch data.

[214] CARB GHG Inventory Fuel Activity data, 2019 update.

[215] *Id.*

[216] CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php

Specifically, crude 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, in fact, 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.



Distillate fuel shares associated with all activities in California, 2000–2019.
Growth in total distillates excluding jet fuel and kerosene from State data.
CHART 4 Data from CEC Fuel Watch and CARB GHG Inventory Fuel Activity Data, 2019 update.

2. The DEIR Fails to Consider Exports in Evaluating the Project's Climate Impact

The DEIR focuses on potential negative effects of reliance on imports if the proposed Project is rejected in favor of alternatives,[217] while ignoring fuels exports from in-state refineries and conditions under which these exports occur – a key factor in assessing the Project's global climate impact, as discussed in the previous subsection. 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

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[217] DEIR pp. 5-3 through 5-7, 5-9, 5-10, 5-19, 5-22 through 5-24.

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.[218] Importantly, before diesel biofuel addition further increased refining of petroleum distillates for export, the structural over-capacity of California refining infrastructure was evident from the increase in their exports after in-state demand peaked in 2006. *See* Chart 4. California refining capacity, especially, is overbuilt.[219] Industry reactions -- seeking to protect those otherwise stranded refining assets through increased refined fuels exports as domestic markets for petroleum fuels declined -- resulted in California refiners exporting fully 20% to 33% of statewide refinery production to other states and nations from 2013–2017.[220] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[221] *See* 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, West Coast (PADD 5) *Supply and Disposition*; www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

Current California and West Coast data 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 related Contra Costa County crude-to-biofuel conversion project. Accordingly, the Project can be expected to worsen in-state petroleum refining overcapacity, and thus the emission shift, by adding a very large volume of renewable diesel to the California liquid combustion fuels mix.

Despite the Project objective to provide renewable fuels to the California market, which could further shift petroleum fuels from this market, the DEIR fails to disclose or evaluate this causal factor in the observed emission shifting impact of recent renewable fuel additions.

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[218] USEAI, 2015.

[219] Karras, 2020. *Decommissioning California Refineries.*

[220] *Id.*

[221] USEIA, West Coast (PADD 5) *Supply and Disposition;* www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

3. The DEIR Fails to Describe or Evaluate Project Design Specifications That Would Cause and Contribute to Significant Emission-Shifting Impacts

By failing to disclose and consider refinery export patterns, the DEIR fails to address the essential question of 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 fails to evaluate the degree to which the Project's HEFA diesel production capacity could add to the existing statewide distillates production oversupply, and 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. See Table 3.

Table 3. 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. Pearlson, M., Wollersheim, C., and Hileman, J., A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production, Biofuels, Bioprod. Bioref. 7:89-96 (2013). DOI: 10.1002/bbb.1378. 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, less than the 80,000 b/d feed capacity of the project.

Accounting for fuel yields on refining targeting renewable diesel[222] and typical feed and fuel densities noted in Table 3, at its 55,000 b/d processing capacity the Project could produce approximately 1.86 million gallons per day of renewable diesel, potentially resulting in crude

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[222] Pearlson et al., 2013.

refining for export of the equivalent petroleum distillates volume if current patterns continue. State default emission factors for full fuel chain "life cycle" emissions associated with the type of renewable diesel proposed[223] account for a range of potential emissions from lower ("residue") to higher ("crop biomass") emission feeds, also shown in the table. The net emission shifting impact of the Project based on this range of state emission factors could thus be approximately 3.96 to 5.72 million metric tons (Mt) of CO_2e emitted per year. Table 3. 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*.

VII. THE DEIR FAILS TO ADEQUATELY DISCLOSE AND ANALYZE THE PROJECT'S AIR QUALITY IMPACTS

As discussed in Section III above, the DEIR is fatally flawed for having chosen a baseline that assumes an operating crude oil refinery rather than actual current conditions, in which the refinery is shut down with no plan or intention to continue processing crude oil. That flaw renders the entire analysis of air emissions in the DEIR inadequate, because the conclusion that the Project "would result in an overall reduction of local criteria pollutant emissions" (DEIR at 4.3-60) is based on a faulty premise and must be revisited; as must all air quality health impacts analysis and cumulative impacts analysis that is grounded in this conclusion. Starting from a zero baseline, the analysis should determine the increase in pollutants associated with operating the Project over current shutdown conditions. Since the calculations in the DEIR indicate that such emissions will be significant and unavoidable using the BAAQMD thresholds of significance, and the DEIR should further identify mitigation measures to address those emissions.

Even aside from the faulty baseline, however, the DEIR analysis of air quality impacts suffers from three major flaws described in the subsections below. First, for reasons discussed in Section VI concerning GHG emissions, the analysis fails to take into account the widely differing air emissions impact associated with both different feedstocks and different product slates. Those differences should have been factored in the reasonable worst case scenario analysis to address uncertainty as to the feedstocks that will be used, *see* Sections II and IV, as well as any other feedstock scenarios appropriate to the analysis. Second, the DEIR air quality analysis systematically excludes acute exposures to short-term episodic facility emissions in nearby communities from consideration, even though the Project risks increasing acute exposures associated with flaring. And third, the DEIR odor analysis of new malodorous feedstock in new and repurposed facilities adjacent to vulnerable populations is too cursory and incomplete to approach sufficiency.

A. The DEIR Air Impacts Analysis Fails to Take Into Account Varying Air Emissions from Different Feedstocks and Crude Slates

Section VI demonstrates that GHG emissions vary significantly with differing feedstocks and product slates. For these same reasons and others, emissions of multiple air pollutants vary with feedstock and product slate as well. Processing a different type of oil – including crude feedstock oils – can increase processing emissions in several ways. It can introduce

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

contaminants that escape the new feed and pass through the refinery into the local environment. It can require more severe, more energy-intensive processing that burns more fuel per barrel, increasing combustion emissions from the refinery. At the same time, processing the new feed can change the chemistry of processing to create new pollutants as byproducts or create polluting byproducts in greater amounts.

There are also potential increases in emissions of air pollutant emissions – including nitrogen oxides, particulate matter, sulfur dioxide, and polycyclic aromatic hydrocarbons, among others – associated with fossil fuel combustion and energy demand in proposed Project processes. The emissions result not only from the more intense hydrogen demands associated with certain feedstocks (*see* Section VI), but from the higher energy demands in addition to hydrogen reforming associated with processing certain types of feedstocks. More contaminated or difficult to pretreat feeds may require more energy in the proposed new feed pretreatment plant. Feeds that are more difficult to process may require more recycling in the same hydrotreater or hydrocracker, such that processing each barrel of fresh feed twice, for example, may double the load on pumps, compressors, and fractionators at that process unit, increasing the energy needed for processing. As another example further downstream in the Refinery, feeds that yield more difficult to treat combinations of acids and sour water as processing byproducts may need additional energy for pretreatment to prevent upsets in the main wastewater treatment system. Feeds that require more energy-intensive processing of this nature may increase combustion emissions of an array of toxic and smog-forming pollutants, including but not limited to those noted above.

Additionally, contaminants in the feedstocks themselves can be released during processing, adding to the air emissions burden. Fish oils can be contaminated with bio-accumulative lipophilic toxins such as polychlorinated biphenyls, dioxins, and polybrominated diphenyl ethers, which could be released from processing at 48,000 barrels per day in cumulatively significant amounts. So-called “brown grease” collected from sewage treatment plants – another potential feedstock whose use has not been ruled out - can adsorb and concentrate lipophilic toxic chemicals from across the industrial, commercial and residential sewerage collection systems—disposal and chemical fate mechanisms similar to those that have made such greases notoriously malodorous.

B. The DEIR Fails to Assess the Likelihood of Increased Air Pollution Associated With the Increased Likelihood of Process Upsets[224]

As discussed in Section V, running biofuel feedstocks risks increasing the likelihood of process upsets and flaring incidents at the Refinery. Any such incident will result release of in a significant volume of uncontrolled air emissions. Accordingly, the DEIR should have addressed those emissions, and ways to mitigate them,as part of its air quality impacts analysis. Specifically, the DEIR should have determined whether increased flaring is likely as a result of HEFA processes (per Section V); described the air impacts associated with flaring (which are

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[224] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled “Air Quality and Hazard Release Impacts of Project Flaring that Available Evidence Indicates Would be Significant are Not Identified, Evaluated, or Mitigated in ihe DEIR.”

acute rather than chronic); and evaluated the possibility of limits on certain feedstocks prone to cause flaring as a mitigation measure.

1. The DEIR Did Not Describe the Air Quality Impacts of Flaring

Although the inclusion of repurposed refinery flare systems in the Project clearly anticipates their use, and serious local air impacts have long been known to occur as a result of refinery flares, the DEIR simply does not describe those impacts. This is a fatal flaw in the DEIR independently from its flawed baseline analysis since, as discussed in Section V, the Project is likely to increase process upset incidents at the Refinery.

The County cannot argue that data for this essential impact description were not available. As described in a recent technical report:

> Causal analysis reports for significant flaring show that hydrogen-related hazard incidents occurred at [the Phillips 66 Rodeo and Marathon Martinez] refineries a combined total of 100 times from January 2010 through December 2020 ... on average, and accounting for the Marathon plant closure since April 2020, another hydrogen-related incident at one of those refineries every 39 days.
>
> ... Sudden unplanned or emergency shutdowns of major hydro-conversion of hydrogen production plants occurred in 84 of these 100 reported safety hazard incidents. Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in22 of these incidents. ... In four of these incidents, consequences of underlying hazards included fires in the refinery.
>
> ... Refinery flares are episodic air polluters. Every time the depressurization-to-flare safeguard dumps process gases in attempts to avoid even worse consequences, that flaring is uncontrolled open-air combustion. Flaring emits a mix of 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 incidents described above flared more than two million cubic feet of vent gas each, and many flared more than ten million.
>
> ... In 2005, flaring was linked to episodically elevated local air pollution by analyses of a continuous, flare activity-paired, four-year series of hourly measurements of the ambient air near the fence lines of four Bay Area refineries. By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares. These same significance thresholds were used to require [Phillips 66 and Marathon and previous owners of the Rodeo and Martinez refineries] to report the hazard data described above.
>
> ... Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the P66 Rodeo and MPC Martinez refineries discussed above *individually* exceeded a relevant environmental significance threshold for air quality.[225]

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[225] Karras, 2021a.

2. The DEIR Failed to Describe the Impact of Feedstock Switching on Flaring

With regard to causal factors for flaring, the allusion in the DEIR to reduced process hazards because the Project would result in fewer onsite equipment units where incidents could occur is specious. The hundred incidents described above include only those in which the type of process units to be repurposed for the Project *and* hydrogen-related hazards were causal factors in an environmentally significant flaring incident.[226] Had the DEIR evaluated the same data source, [227] the County could have found that the same refining processes that would be repurposed for the Project dominate the historic refinery flaring pattern.

All of the uniquely pronounced inherent process hazards resulting from converting crude refineries to HEFA refineries—which is what the Project proposes—result in *designing* HEFA conversions to dump process gas to flares when such hazards arise. The increased exothermic runaway reaction hazard due to more hydrogen-intensive processing of HEFA refining than crude refining, and associated need for upgraded capacity for rapid depressurization to flares, are noted industry-wide.[228] [229] Failure to evaluate this potential for Project HEFA refining to increase the frequency of refinery flaring compared with historic crude refining at the site is a major deficiency in the DEIR flaring analysis. Had the DEIR performed this essential evaluation, the County could have found that:

> [D]espite current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the P66 Rodeo and MPC Martinez refineries frequently. ... [S]witching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents ...
>
> ... The increased risk of process upsets associated with HEFA processing concomitantly creates increased risk to the community of acute exposures to air pollutants ... Therefore, by prolonging the time over which the frequent incidents continue, and likely increasing the frequency of this significant flaring, repurposing refineries for HEFA processing can be expected to cause significant episodic air pollution."[230]

3. The DEIR Failed to Evaluate the Likelihood of Increased Flaring

Refinery flare incidents can be prevented by the same measures that can prevent the catastrophic explosion and fire incidents which flares are designed to (partially) mitigate; removing the underlying causes of those hazards. From and an environmental health and safety perspective, this is the crucial fact about flaring. In this regard, its incomplete and misleading allusion to flaring as merely a way to make refining safer, which incidentally emits some

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[226] Karras, 2021a.

[227] 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. *See* Karras, 2021c, Attachment 33.

[228] van Dyk et al., 2019.

[229] Chan, 2020.

[230] Karras, 2021a.

pollutants, obscures a third fatal flaw in the DEIR flaring analysis: it failed to address the elective processing of feedstock types that would cause preventable flaring.

Refinery flares are designed and permitted for use only in emergencies, the only exception being limited to when unsafe conditions are both foreseeable *and* unavoidable.[231] Here in the Bay Area, preventable refinery flaring is an unpermitted activity that contravenes air quality policy and law.[232] The DEIR fails to address this fact. The DEIR declines to expressly define or limit the feedstocks that will be used, without addressing the issue that electing to process some of those feeds rather than others could result in more frequent environmentally significant flaring impacts, contrary to air quality policy and law.

Had the DEIR addressed this issue, the County could have found that:

- A portion of the range of potential HEFA feedstocks, including soybean oil, distillers corn oil and most other crop oils, have relatively higher process hydrogen requirements than other potential feedstocks for Project biofuel refining;[233]
- Electing to process feedstocks in that high process hydrogen demand category would release more heat during processing, thereby increasing the frequency of process temperature rise hazard incidents and hence environmentally significant flaring;[234] and
- The resultant more frequent flaring from electing a feedstock which unnecessarily intensified underlying flaring would be preventable since another feedstock would reduce flaring frequency in accordance with air quality policy and law, and consequently, the proposed Project flaring could result in significant impacts.

C. The DEIR Fails to Address Acute Episodic Air Pollution Exposures

Although as described in the previous subsection flaring causes acute episodic air pollution exposure and will increase in frequency with the Project, the DEIR systematically excludes acute exposures to short-term episodic facility emissions associated with flaring and process upsets from consideration. The facility air permit itself specifies hourly and daily as well as annual emission limits.[235] Yet the DEIR it erroneously conflates these acute and chronic exposure impacts, drawing numerous conclusions that facility emission impacts of the Project are less than significant based on average rates of emission from continuous sources alone; and fails entirely to disclose or address episodic emissions from potentially increased flaring, and their potential health impact..

Potential air quality impacts associated with acute exposures to short-term episodic emissions from the refining facilities are systematically excluded from DEIR consideration. The DEIR fails to evaluate or address episodic emissions from flaring, as discussed directly above in

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[231] The limited exception does not apply where, as here, known measures to avoid flaring can be taken before unsafe conditions that result in flaring become locked into place, e.g., the inherently safer processing systems and designs are identified and can be implemented during construction or implementation.

[232] BAAQMD Regulation 12, Rule 12.

[233] Karras, 2021a.

[234] Karras, 2021a.

[235] Major Facility Review Permit Issued To: Phillips 66–San Francisco Refinery, Facility #A0016, Dec. 27, 2018.

subsection B. Even for criteria air pollutants, the DEIR calculations and estimates fail to account for combined effects of site-specific source, geographic, demographic, and climatic factors that worsen episodic air pollutant exposures locally. The DEIR further relies upon incomplete local air monitoring, which could not and did not measure incident plumes. Local air monitoring also excludes from measurement many air pollutants associated with upsets and flaring. Polycyclic aromatic hydrocarbons, carbonyl sulfide, dioxins, and even particulate matter less than 2.5 microns diameter ($PM_{2.5}$), for example, are not measured continuously in local air samples, such that episodically elevated one-minute or one-hour exposure levels during flaring remain unmeasured for these and many other chemicals known or suspected to be released by flares. The DEIR's error of conflating impacts of acute and chronic air pollutant exposures obscures its failure to consider acute exposure to short-term episodic emissions. In most cases, its comparisons underlying those conclusions appear to be grounded in no acute exposure or episodic emission data at all.[236]

Additionally, the DEIR failed to consider potential means of mitigating the impact of flaring associated with HEFA processes by limiting uses of the feedstocks most prone to causing excess flaring. As discussed in Section VI, a portion of the range of potential HEFA feedstocks, including soybean oil, distillers corn oil and most other crop oils, have relatively higher process hydrogen requirements than other potential feedstocks for Project biofuel refining;[237]Processing feedstocks with higher hydrogen demand releases more heat during processing, thereby increasing the frequency of process temperature rise hazard incidents -- and hence environmentally significant flaring.[238] The DEIR should therefore have considered the possibility of capping or prohibiting the use of feedstocks with higher risk of causing flaring incidents.

The DEIR must therefore be revised to include a disclosure and assessment of the likelihood of increased flaring associated with the proposed HEFA process, including reasonable worst case scenario analysis taking into account variation in flaring associated with different feedstocks. It must then calculate the increased acute air pollution associated with such flaring, and identify potential mitigation measures to diminish the likelihood of flaring associated with the HEFA process, including feedstock limitations.

D. The DEIR Fails to Adequately Address Potential Odors from the Project

Phillips 66 engineered some odor management measures such as leak seals and carbon cannister treatment of odorous streams associated with the Project. The DEIR concludes that the Project would result in a significant odor impact despite the engineered measures, but concludes that odor impacts could be reduced to less than significant through use of an "Odor Management Plan" -- to be developed, implemented, maintained, monitored and updated as necessary *after* Project approval. 4.3-80 – 81. The DEIR does not discuss the effectiveness or pitfalls observed from prior or existing use of odor management plans at the Refinery.

The DEIR's reliance on a not-yet-developed odor management plan is misplaced. In the first instance, such a plan runs afoul of the CEQA requirement that "Formulation of mitigation

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[236] Karras 2021c.
[237] Karras, 2021a.
[238] Karras, 2021a.

measures shall not be deferred until some future time." CEQA Guidelines § 15126.4(a)(1)(B); and that "Mitigation measures must be fully enforceable through permit conditions, agreements, or other legally-binding instruments." *Id.* at § 15126.4(a)(2).

Additionally, as a substantive matter, the DEIR does not adequately describe how the proposed mitigation would be effectively at reducing impacts to non-significance – specifically, how "odors similar to an animal and/or food processing facility unless properly managed" would be eliminated in the context of an open-plan petroleum refinery surrounded by densely packed communities. Moreover, any proposed mitigation – and description of its effectiveness – must account for the fact that the DEIR does not preclude use of any type of feedstock – meaning that a reasonable worst case scenario analysis must account for the possibility that highly odorous feedstocks will be used. The DEIR states that Project feedstocks could include "FOG" (fats, oils and grease) – a category of feedstock includes a particular type of "brown grease." Brown grease is a highly malodorous oil and grease extracted from the grease traps, "mixed liquor" (microbial cultures with their decomposition products) and "biosolids" (sewage sludge) in publicly owned treatment works, commonly known as sewage plants, originating in the broad mix of residential, commercial and industrial waste water connections to sewage plants across urban and suburban landscapes.

The DEIR fails to adequately describe or account for malodorous properties of brown grease and other types of FOG in its impact evaluation. The DEIR further fails to provide a sufficiently detailed description and analysis of the infrastructure from which the odors may be emitted – including the transport system, the storage system, and the pre-processing system – including design specifications, potential points of atmospheric contact, and the proximity to adjacent populations. Such analysis is crucial to supporting the DEIR conclusions that an odor management plan will reduce the impact to less than significant.

VIII. THE DEIR'S ASSESSMENT OF ALTERNATIVES TO THE PROJECT IS INADEQUATE

Analysis of project alternatives, together with identification of mitigation, form the "core of the EIR." *Jones v, Regents of University of California* (2010), 183 Cal.App.4th 818, 824-25. That core is deeply flawed here. First, the document fails to consider a "no project" alternative that realistically represents conditions without the project, since those conditions do not include an operating refinery. Second, the alternatives analysis artificially conflates numerous alternatives that can and should have been considered collectively as a means to reduce Project impacts. Second, while the analysis appropriately includes an electrolytic hydrogen alternative, the analysis of that alternative omits important criteria that should have been considered. Finally, the DEIR defines the Project in a manner that is so overly narrow as to skew the analysis of alternatives.

A. The DEIR Does Not Evaluate A Legally Sufficient No-Project Alternative

In examining a range of alternatives, an EIR is required to include a "no project" alternative to facilitate assessment of the impact of the remaining alternatives. "The purpose of describing and analyzing a no project alternative is to allow decisionmakers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project. ..." CEQA Guidelines § 15126.6(e)(1). "The 'no project' analysis shall discuss the existing conditions ... as well as what would be reasonably expected to occur in the foreseeable future if the project were not approved, based on current plans and consistent with available infrastructure and community services. ..." CEQA Guidelines, § 15126.6, subd. (e)(2). It is essential that the "no project" alternative accurately reflect the status quo absent the project, to ensure that the baseline for measuring project impacts is not set too high, which would artificially diminish the magnitude of Project impacts. *See Ctr. for Biological Diversity v. Dep't of Fish & Wildlife* (2014), 234 Cal.App.4th 214, 253 (citation omitted) (emphasis in original) ("a no project alternative in an EIR 'provides the decision makers and the public with specific information about the environment if the project is not approved. It is a factually based forecast of the environmental impacts of *preserving the status quo*. It thus provides the decision makers with a base line against which they can measure the environmental advantages and disadvantages of the project and alternatives to the project.'").

For reasons explained in Section II, concerning the project baseline, the DEIR incorrectly identified the no project alternative as the scenario where crude oil operations would return to historic rates, continuing crude oil processing operations indefinitely at historic levels. DEIR at 5-11. *See* DEIR at 3-37 (stating, in the discussion of baseline, that if the Project is not implemented, petroleum crude refining would continue at historic rates because Refinery throughputs will rebound from the lower level during the COVID-19 pandemic to "more typical" historic throughputs). Yet the DEIR provides no substantial evidence to support this conclusion. It is an unsubstantiated assumption contradicted by mountains of evidence – much of it provided in the Scoping Comments and even more provided in these Comments – that Phillips 66 will be winding down petroleum refining operations at the Refinery regardless of whether the Project is approved. It is imperative, to ensure a rational alternatives analysis, that the County include a no project alternative that is grounded in reality.

The validity of the no project alternative analysis is further undercut by the DEIR's faulty consideration of near-term future fuel market demand, as described in the next subsection. The Refinery cannot meet refined products demand (to the extent it exists) if it cannot access the feedstock to make those products in the first place – as is clearly the case. This fact undercuts the DEIR analysis of the no project alternative to the extent that analysis assumes, without considering feedstock supply, that the Refinery is positioned on a foregoing basis to meet purported product demand.

A no project alternative reflecting the reality of the Refinery's closure would have found multiple significant impacts where the DEIR currently finds no significant impact or, in some cases, reduced impact. If, in fact, the Santa Maria refinery and/or the Rodeo refinery are being forced by current circumstances to limit or cease crude oil production, then no project conditions would likely have less environmental impact than any Project alternative. It is thus crucial that the County assess complete information concerning the volume of crude that would be refined at the Santa Maria and Rodeo facilities – if, indeed, any would be – in the absence of the Project.

Additionally, a no project alternative reflecting that reality would need to address the need to decommission the refinery and address any hazardous waste issues, as discussed in Section X. The DEIR needs to confront the reality that if the Project is not approved, a massive – and environmentally impactful – cleanup effort will be required to address the decades of hazardous contamination fouling the idled site.

B. The DEIR Analysis Rejecting Three Reduced Production Alternatives is Grounded in Erroneous Assumptions Regarding Petroleum Fuel Markets

The DEIR dismissed from consideration three alternatives involving decommissioning or production reduction: the alternative of shutting down the Santa Maria facility but continuing operations at the Refinery (DEIR at 5-3 – 4), the alternative of eliminating gasoline blending (DEIR at 5-4), and the full decommissioning alternative (DEIR at 5-9 – 10). These alternatives, as well as the no project alternative, were evaluated and rejected based on stated assumptions regarding crude oil supply and refined products markets. The analysis rejecting these alternatives is consistently grounded in an assumption that the Refinery is essential to meet regional refined product demand..

Specifically, the DEIR hypothesizes that decommissioning would lead to transportation fuels supply/demand imbalances which "would likely lead to regional shortages that could trigger imports and higher prices" in the "near term." DEIR at 5-9. Similarly, in rejecting the decommissioning of the Santa Maria facility only alternative, the DEIR states, "Phillips 66 is a critical supplier of transportation fuels to the region," and that "any reduction in regional supply will result in increased imports of gasoline from other areas." DEIR at 5-3 – 4. It further posits that rebounding post-COVID fuels demand, coupled with the closure of the Marathon Martinez refinery, could "reduce regionally-available supply to meet regional demand" for petroleum fuels if the Santa Maria facility closes (DEIR at 5-3) and "would likely lead to regional shortages that could trigger imports and higher prices" if the Rodeo facility closes. DEIR at 5-9. Additionally, the DEIR states, in rejecting the elimination of gasoline blending, that "Phillips 66 is a critical supplier of conventional transportation fuels to the region."

These statements regarding fuels supply and demand, however, are demonstrably rebutted by facts – undercutting the entire logic of its rejection of the three reduced production alternatives. While the DEIR asserts a concern that in the rejected alternative scenarios, near-future demand for refined products will exceed supply in the fuels market, leading to increased imports and attendant gas price spikes, and references generally a "tightening" of the supply/demand balance for diesel (DEIR at 5-9), it nowhere supports a conclusion that any of the decommissioning or reduction alternatives would actually create a supply shortage. In fact, available evidence indicates the exact opposite. Comparisons of fuels supply, demand, and statewide fuels refining spare capacity while meeting demand and exporting fuels strongly suggest that currently available refining capacity is fully sufficient to meet demand even without both the Refinery and the shuttered Marathon Martinez refinery. This error in the DEIR skews its analysis of the educed production alternatives. This error must be corrected both to accurately describe the no project alternative, and to support a reasonably accurate impacts comparison between alternatives.

It bears note at the outset that under existing conditions, the crucial barrier which limits petroleum fuels movements, hence affecting supply and price, is mountainous terrain between West Coast (PADD 5) and other U.S. refining districts. This leads to normal supply movements between the Bay Area and Southern California[239] -- which the DEIR misleading labels

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[239] USEIA, 2015. *West Coast Transportation Fuels Markets;* U.S. Energy Information Administration: Washington, D.C. https://www.eia.gov/analysis/transportationfuels/padd5

"imports." In fact, as a consequence of this geographic constraint, the existing condition of refinery overcapacity results in both California and the West Coast of the U.S. overall being net *exporters* of gasoline and diesel to other states and nations.[240] This fact calls deeply into question the DEIR's hypothesis that the Refinery is central to local supply.

And in fact, California's on-the-ground experience with supply and demand before and during the pandemic years undercuts the DEIR hypothesis of the necessity of the Refinery for meeting in-state demand. Available supply and demand data show that even after the closure of the Marathon Martinez refinery in 2020, and even after demand for refined products rebounded in 2021 from their early pandemic decline, California refineries have operated significantly under capacity.

California and the West Coast (Petroleum Administration Defense District 5) fuels demand data are summarized in Tables 4 and 5.

Table 4. California Taxable Fuel Sales Data: Return to Pre-COVID Volumes

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

	Demand in 2021	Pre-COVID range (2012–2019)			Comparison of 2021 data with the same month in 2012–2019
		Minimum	Median	Maximum	
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 net taxable fuel sales (CDTFA, various years). Pre-COVID statistics are for the same month in 2012–2019. Multiyear comparison range shown accounts for interannual variability in fuels. Jet fuel totals exclude fueling in California for fuels presumed to be burned outside the state during interstate and international flights.

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[240] USEIA, 2015.

Table 5. 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)			Comparison of 2021 data with the same month in 2010–2019
		Minimum	Median	Maximum	
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 for “Product Supplied” from *West Coast (PADD 5) Supply and Disposition,* (USEIA, various years). Product Supplied approximately represents demand because it measures the disappearance of these fuels from primary sources, i.e., refineries, natural 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. This multiyear comparison range accounts for interannual variability in fuels demand.

These tables show that demand for refined products rebounded to pre-COVID levels in 2021. In California, from April through June 2021 taxable fuel sales 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. *See* Table 4. Similarly, 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. 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. *See* Table5.

Yet throughout this rebound, petroleum refining remained shuttered at the Marathon Martinez refinery with no plans to restart. Nonetheless, California and West Coast refineries supplied the rebound in fuels demand *while running well below capacity*, as summarized in Tables 6 and 7.

Table 6. 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 CEC Fuel Watch, various dates. Statewide refinery capacity as of 1/1/21, after the Marathon Martinez refinery closure, from USEIA, 2021a. 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.

Statewide, four-week average California refinery capacity utilization rates from March 20 through August 6, 2021 ranged from 81.6% to 87.3% (Table 3), similar to those across the West Coast, and well below maximum West Coast capacity utilization rates for the same months in 2010–2019 (Table6). Moreover, review of Table 6 reveals 222,000 b/d to more than 305,000 b/d of spare California refinery capacity during this period when fuels demand rebounded.

Table 7. West Coast (PADD 5) Percent Utilization of Operable Refinery Capacity.

	Capacity Utilized	Pre-COVID range for same month in 2010–2019		
Month	**in 2021**	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	NR	80.4 %	87.2 %	96.9 %
October	NR	76.4 %	86.1 %	91.2 %
November	NR	77.6 %	85.3 %	94.3 %
December	NR	79.5 %	87.5 %	94.4 %

NR: Not reported. Utilization of operable capacity, accounting for downstream refinery bottlenecks, types and grades of crude processed, operating permit constraints, and both scheduled and unscheduled downtime for inspection, maintenance, and repairs, from USEIA, 2021b. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID data for the same month in 2010–2019. 2021 data account for Marathon Martinez closure.

Thus, spare California refining capacity during this period when fuels demand increased to reach pre-COVID levels and crude processing at the Marathon Martinez refinery remained shut down (222,000–305,000 b/d) *exceeded the total 120,200 barrel per calendar day crude capacity of the refinery*.[241] Other refiners could have used that idled capacity to meet this temporary surge in demand and reduction in supply, and would have been incented to do so, had the hypothesized market tightening necessitated it. Yet that is not what actually happened.

In fact, existing conditions—namely idled crude refining assets during the current surge in petroleum fuels demand—show that the unsupported hypothesis of a supply-demand imbalance which threatens to cause local fuel price spikes from greatly increased imports hypothesized in the DEIR is both unsupported and, in the recent demand surge, false. Thus, the DEIR analysis rejecting reduced production alternatives lacks valid factual support.

C. The DEIR Inappropriately Dismissed the Hydrogen Generation Technology Alternative From Consideration

Splitting water with renewable power through electrolysis to produce zero-emission hydrogen (ZEH) is a proven technology that could be installed instead of repurposing fossil gas steam reforming hydrogen plants at the Refinery for the Project. Commentors raised multiple issues in support of ZEH in their Scoping Comment are incorporated herein and reasserted, as they remain relevant and were not addressed in the DEIR.

The DEIR dismisses from consideration the "hydrogen generation technology alternative" (herein ZEH) on the grounds of purported technical and economic infeasibility. DEIR at 5-7 – 9. This conclusion not supported by substantial evidence. It is not based on a facility-specific evaluation of feasibility,[242] but rather a back-of-the-envelope calculation of potential PG&E energy costs based on general information. DEIR 5-7, 5-33 – 34.

In the first instance, the County's rejection of the ZEH alternative is baseless in view of the fact that this same alternative was treated as feasible in the DEIR for the Marathon Martine project - a discrepancy that the County makes no attempt to reconcile. Nothing in either DEIR provides any reason why the Rodeo Renewed project differs in any way from the very similar Marathon project that would affect the feasibility of the hydrogen alternative. On that basis alone, the rejection of this alternative is unsupported by substantial evidence.

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[241] Although USEIA labels the SFR refining site as Rodeo, both RF and SMF equipment capacities are included in the USEIA data table reporting the 120,200 b/cd operating and total operable capacity of the refinery. *See* USEIA, 2021a. *Refinery Capacity Data by Individual Refinery as of January 1, 2021;* U.S. Energy Information Administration: Washington, D.C. Accessed 3 Nov 2021. https://www.eia.gov/petroleum/data.php

[242] Commenter NRDC submitted a Public Records Act request to the County for analysis associated with the cost estimates at DEIR 5-7 – 5-8, and "[a]ny and all additional records pertaining to electrolysis or 'green' hydrogen at the Phillips 66 Rodeo refinery in connection with the Rodeo Renewed project and associated California Environmental Quality Act (CEQA) review." Letter dated November 9, 2021 from Ann Alexander to Lawrence Huang. In response, via the email from Lawrence Huang to Ann Alexander also dated November 9, 2021, the County provided no site-specific analysis concerning the rejected electrolysis hydrogen alternative.

Beyond that basic problem, the DEIR provides no valid basis for rejection of the electrolytic hydrogen alternative as infeasible. The document presents only general information concerning the technology and a statement of arithmetic that is both obvious and meaningless, without considering an array of factors that could make electrolytic hydrogen necessary and both economically and technically feasible.

ZEH should have been considered as an alternative in the DEIR for the reasons specified below.

1. The DEIR Failed to Consider ZEH as Mitigation for Significant Project Impacts

The Project has reasonable potential to result in multiple significant impacts that the DEIR did not identify and remain unmitigated in the DEIR, as explained in Section V. A major part of that impact would be accounted for by the proposed repurposing of fossil gas hydrogen steam reforming plants. See Sections II and VI. Project hydrogen plant emissions alone could reach approximately 1.5 to 2.3 million metric tons per year.[243] ZEH would eliminate those steam reforming emissions. However, having failed to identify this significant potential GHG impact, the DEIR failed to propose mitigation for it. ZEH should have been considered as such a mitigation measure.

The cursory, general, and flawed cost analysis provided as a reason for rejecting ZEH was clearly focused solely on the cost to the Project proponent. As discussed in subsection 3, this is not a reasonable sole basis for rejecting a needed mitigation measure.

2. The DEIR Ignored a Critical Fact Supporting the Scalability of ZEH

The DEIR concluded that ZEH would be technically infeasible based on the large scale of total ZEH hydrogen production that would be needed by the Project. DEIR at 5-8. However, this conclusion is based on an implicit flawed assumption about how scalability of ZEH works – *i.e.*, that a demonstration at small scale does not support a conclusion of feasibility on a larger scale. That assumption does not reflect the nature of the technology, which makes ZEH inherently scalable. This is because ZEH consists of multiple smaller electrolyzer units, that can be stacked to the desired total production scale. Indeed, the DEIR recognizes the modular nature of ZEH technology, stating, "At this time, the largest electrolyzer in service is 20 MW ... meaning that approximately 37 units would need to be installed to supply the necessary amounts of hydrogen. Electrolysis projects similar in size to that requires for the Rodeo Refinery have been announced ... ." *Id.* Yet without further analysis, and without consideration of the import of this modular construction for scalability, the DEIR concludes in the same paragraph of the same page that ZEH is "infeasible for both technical and financial reasons" – with the reason given that "[t]he scale of the electrolysis operation that would be required [exceeding] any facility that has been put into operation in the world." *Id.*

Indeed, as an example of a large PEM hydrogen facility, Shell plans to scale up the capacity of a proton exchange membrane (PEM) hydrogen electrolysis plant in Germany from the current 10 megawatts to 100 megawatts.[244] Furthermore, Reed et al used a scale factor of 0.9

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[243] Karras, 2021a.

[244] https://www.shell.de/media/shell-media-releases/2021/shell-energy-and-chemicals-park-rheinland.html

for projecting cost of larger central installations in their analysis of the costs of electrolysis hydrogen production. [245]

3. The DEIR Rejected ZEH Based on Unsupported, Invalid and Biased Cost Analysis

The DEIR concluded that ZEH is financially infeasible without disclosing, evaluating, or apparently attempting virtually any of the elements of a valid cost analysis specific to the site and Project. A Public Records Act request from Commenter NRDC seeking information concerning the cost calculation turned up essentially no support for it.[246]

The DEIR did not identify the electrolysis technology or technologies to which its cost conclusion pertained. In fact, there are three types of electrolysis technology, each with its own capabilities, limitations, site footprint and costs.[247] The DEIR also did not present any verified onsite power cost. Had it done so, the County might have found costs of self-generated wind or solar power may be as low and 2.6 cents per kilowatt-hour (kWh),[248] thus lower than the $120/MWh for third-party power at current utility rates the DEIR asserted. DEIR at 5-8. Moreover, the DEIR failed to disclose that crude refineries in California may contract with utilities for refinery-specific power sales as well as power purchases at potentially lower cost to refiners. Rather, the DEIR asserted that $120/MWh power cost based, apparently, on general utility rates, without disclosing or evaluating the rate Phillips 66 actually pays for grid power.

It is particularly problematic that the DEIR relays ZEH capital cost estimates from Phillips 66 of $0.75 billion to $1.1 billion (DEIR at 5-8) without disclosing any attempt to verify that information, as noted above. Had it attempted a contemporary survey, the DEIR might have found current ZEH capital costs, which as expected are trending downward, of approximately $500 to $650 per kW[249] -- which, again, would be lower, had the DEIR checked and found that available information, at approximately $0.37 billion to $0.48 billion.

Other cost data is generally available as well, and should have been considered by the County. Hydrogen companies, such as Nel Hydrogen, which has US operations, can provide estimated construction costs of a ZEH facility.[250] Operating costs can also be readily determined based on the source of renewable energy, which can be from both an on-site solar facility and from the grid. The cost of the solar facility is minimal, with it being built on the refinery's contaminated property that cannot be used for other purposes. There is only the cost of installing the panels, and the maintenance cost is minimal. Furthermore, using green grid electricity will allow the flow of green energy to go both ways, with the ZEH being used to balance the grid

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[245] Reed et al, p. A-10..

[246] Letter dated November 9, 2021 from Ann Alexander to Lawrence Huang. In response, via the email from Lawrence Huang to Ann Alexander also dated November 9, 2021.

[247] Reed et al., 2020. Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California; California Energy Commission Clean Transportation Project Final Project Report. Prepared for the Commission by U.C. Irvine Advanced Power and Energy Program. June 2020. CEC-600-2020-002.

[248] Personal communication, Clair Brown and Greg Karras with Jeffrey Reed, U.C. Irvine Advanced Power and Energy Program, on Monday, 6 December 2021.

[249] *Id.*

[250] Typically brownfield construction costs 10% less that greenfield production, which is in line with using a factor of 0.9 to predict the cost of scaling up the modular ZEH.

during peak hours. The benefit of grid balancing is large and depends on the opportunity costs of grid balancing using batteries and gas peaker plants, both of which have high costs.

Furthermore, the DEIR failed to take into account cost scaling factors. Consequently, despite asserting the unprecedented scale of the Project ZEH need as a reason for rejecting ZEH as infeasible (DEIR at 5-8), the DEIR failed to disclose or evaluate this exactly opposite effect of scale: larger centralized ZEH installations, and especially brownfield installations, which would be the Project condition, are cheaper per kW installed than smaller installations. Even a cursory check by the DEIR could have informed the County that the hydrogen road map analysis the California Energy Commission and U.C. Irvine reported for state consideration of climate stabilization pathways applies a scaling factor of 0.9,[251] thus quantifying *reduced* incremental cost with increasing scale for the large-scale ZEH installation it asserts.

Additionally, the net costs (costs minus benefits) for the ZEH alternative is not even mentioned, with only the private costs assumed to be too high. In view of the very high GHG emissions and other air pollution from the legacy gray hydrogen facility, ZEH a major economic and social benefit. For this reason, the costs and benefits of the alternatives examined should have been evaluated not only in the context of project economics, but also the larger context of social costs. For example, the County can estimate the public health costs of the $PM_{2.5}$ emissions from the hydrogen operations on people living nearby.[252] Because the Refinery is situated in a densely populated urban area, the health costs from the pollution caused by the hydrogen operation are very high, and the comparable health costs from ZEH are zero.

Finally, despite describing LCFS credits which would be available to the Project, the DEIR stacks the deck against ZEH by excluding costs to the refiner associated with forgoing those credits for ZEH-produced renewable fuels. It states that "the capital costs of hydrolysis technology make it financially infeasible compared to the steam reformation process currently employed at the Rodeo Refinery" (DEIR at 5-8), but ignores the LCFS debit costs of that fossil steam reforming. Had this analytical bias been absent, the DEIR could have found that, by eliminating the approximately 1.5 to 2.3 million metric tons of annual emissions cited above, with current and future LCFS credits of $100 to $200 per metric ton, ZEH could provide cost savings in the range of $150 million to $460 million annually, or $1.5 billion to $4.6 billion over ten years. These savings that the DEIR could have found exceed the likely-inflated ZEH capital cost of $0.75 billion to $1.1 billion that the DEIR reports from unverified refiner estimates. DEIR at 5-8.

The DEIR, however, failed to seek, disclose or evaluate any of this data and information. The analysis of the ZEH alternative should not only have found the alternative to be feasible, but in considering it should have evaluated the ways in which this alternative would mitigate the Project's significant impacts – as identified in these Comments but not addressed in the DEIR.

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[251] Reed et al., 2020.

[252] Each 1 µg/m3 of PM2.5 that reaches 100,000 people living nearby causes 2.3 premature deaths annually. With a Value of a Statistical Life of $10,000,000 estimated by the EPA in 2019, then causing each additional 2.3 deaths leads to a social cost of $25M annually. Burnett R, Chen H, Szyszkowicz M et al. 2018; Global estimated of mortality associated with long-term exposure to outdoor fine particulate matter, PNAS 115 (38):9592-9597.

D. The DEIR Alternatives Analysis Artificially Separates Alternatives that are Not Mutually Exclusive

In addition to the (inappropriately characterized) no project alternative, the DEIR considered three additional alternatives in addition to the Project: the "reduced project" alternative, the "terminal only" alternative, and the "no temporary increase in crude oil" alternative. DEIR at 5-11 – 34. These alternatives were among those appropriate for consideration, as they are feasible means to reduce Project impacts. However, the DEIR presents no reason why two of these – the reduced project alternative and the no temporary increase alternative - were evaluated as separate options rather than collectively. Nothing about them is mutually exclusive: the Project could have been reduced in scale *and* completed without the no temporary increase in crude throughput over the wharf. The DEIR should therefore have either considered those two alternatives collectively in addition to separately, or else provided sufficient evidence and reasoning as to why this combined approach would not be feasible.

E. The Project Purpose is Defined in a Manner So Narrow as to Skew the Analysis of Alternatives

The Project objectives are drawn in an overly narrow fashion that may unfairly bias consideration of the green hydrogen alternative. The list of Project objectives in the DEIR twice references a goal of repurposing Refinery infrastructure ("convert existing equipment and infrastructure" and "repurpose and reuse the facility's existing equipment capacity"). DEIR at 3-22. However, framing the Objectives in this manner by nature weighs against any alternatives – such as the green hydrogen alternative – that would upgrade and replace heavily polluting refinery infrastructure while still allowing biofuel production to proceed. The fundamental goal of the Project is to manufacture biofuels; "repurposing" is merely a strategy by which Phillips 66 seeks to hold costs down. Why the company may for that reason consider repurposing economically advantageous, allowing every strategy to economize to rise to the level of a fundamental Project objective would bias the CEQA process in favor of the cheapest and most polluting alternatives, and against alternatives that are costlier but more environmentally sound. Defining project objectives in such an "artificially narrow" fashion violates CEQA. *North Coast Rivers Alliance v. Kawamura* (2015), 243 Cal.App.4th 647, 654.

IX. THE DEIR'S ANALYSIS OF CUMULATIVE IMPACTS WAS DEFICIENT

CEQA requires a cumulative project impacts analysis because "the full environmental impact of a proposed ... action cannot be gauged in a vacuum." *Whitman v. Board of Supervisors* (1979) 88 Cal.App.3d 397, 408. Cumulative impacts refer to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts. Guidelines §15355. The cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. *Id.* The discussion of each type of cumulative impact in an EIR need only be proportional to the severity of the impact and the likelihood of its occurrence, Guidelines § 15130(b), but even an insignificant impact must be justified as such, Guidelines § §15130(a). For each cumulative impact, its geographic scope must be supported by a reasonable explanation. Guidelines §

15130(b)(3). Otherwise, an underinclusive cumulative impacts analysis "impedes meaningful public discussion and skews the decision maker's perspective concerning the environmental consequences of a project, the necessity for mitigation measures, and the appropriateness of project approval." *Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 431. *See also Friends of the Eel River v. Sonoma County Water Agency* (2003) 108 Cal.App.4th 859.

The cumulative impacts analysis in the DEIR falls far short of these requirements, and fails to meet basic criteria for rationality. The DEIR largely confined its cumulative impacts analysis to projects located within 3 miles of the Project site or Santa Maria facility. No rationale or evidentiary support is provided for use of this particular geographic limitation; or, indeed, for selecting the evaluated projects based on a geographic limitation at all. The suite of projects swept up in this 3-mile radius are random and highly disparate, many being radically different in type from the Project and having few if any correlative impacts. These "cumulative" projects include, *inter alia,* a waterfront park, a mixed-use building, and a water purification project. DEIR at 6-3 – 5.

The very similar Marathon Martinez biofuel conversion project, lost in this strange mix, receives barely a mention in the analysis. The Marathon project is described in a single paragraph, but "discussion" of its cumulative impacts consists only of passing single-sentence and non-substantive general references such possible impacts – and those only including impacts to marine species, hazardous materials risks, and water quality. DEIR at 6-6, 8 – 9.

This approach is deficient in multiple respects. First, other than articulating very general criteria (DEIR at 6-2 – 3), the DEIR failed to specify a specific rational basis for the universe of projects considered in the cumulative impacts analysis – with respect to either the 3 mile radius or the particular array of projects evaluated within that radius. In particular, it failed to explain why projects were included in the cumulative impacts analysis whose impacts are clearly unrelated in type to the impacts of the Project. Second, the analysis is almost entirely non-quantitative, even though the Project's impacts are quantified with respect to key issues, including criteria air pollutant emissions and GHG emissions. And third, the document contains functionally zero cumulative impacts analysis of the Project as considered together with the closely related Marathon Martinez project, even though the two projects will necessarily have very similar impacts, and will cumulatively impact regional air quality, upstream agricultural land use, and the State's climate goals to a significantly greater degree than the impact of each project individually.

Rather than taking the unreasoned approach it did, the DEIR should have identified a universe of projects to include in its analysis based on information concerning those projects' impacts, and the likelihood that they will intersect with the impacts of the Project. Including a compliment of local projects in that universe would be appropriate when analyzing cumulative impacts that are local in scale; but confining the analysis entirely to local projects does not make sense with respect to project impacts that are regional (e.g., air quality impacts), statewide (impact on the state's climate policy), or national and international (climate, upstream indirect land use impacts).

Using these criteria, it is clear that, at minimum, comparable refinery biofuel conversion projects – including but not limited to the Marathon project – needed to be included in the cumulative impacts analysis. The refinery feedstock market is national, and even global, in scale. Both biodiesel and renewable diesel projects in the United States compete for the same, limited supply of crop oils and animal fats. As a result, a cumulative impacts analysis should have included existing HEFA projects currently under construction and proposed in California, such as the AltAir Paramount[253] and Alon Bakersfield[254] refinery projects as well as anticipated future conversion projects nationwide that are likely to produce similar large-scale impacts – e.g., due to anticipated use of similar feedstocks because of similar processing technology or transportation routes.

The following sections discuss particular categories of cumulative impacts that should have received scrutiny in the DEIR but did not.

A. The DEIR Should Have Analyzed the Cumulative Impact of California and Other US Biofuel Projects on Upstream Agricultural Land Use

As discussed in Section IV.D above, the Project alone has the potential to consume an enormous portion of the entire US production of the agricultural products it proposes to use as feedstocks. Project feedstock demand could boost demand for biofuel feedstock oils, currently 113,000 b/d nationwide total, by 71% (80,000 b/d). The Project could in principle, standing alone, consume up to 39 percent of the total U.S. soybean oil production for all uses.

The similar Marathon Martinez conversion project would cumulatively impact feedstock consumption levels, and hence on agricultural resources and their availability. As Commenters described in separate comments concerning the DEIR for that project, the Marathon project could increase demand for biofuel feedstock oils by 42% and could consume up to 24 percent of the nation's total production of soybean oil for all uses.[255] Yet the overall limitation on HEFA feedstock availability is well documented within the scientific community,[256] the financial

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[253] *See* Lillian, Betsy. "World Energy Acquires AltAir Renewable Fuel Assets in California." March 22 2018. https://ngtnews.com/world-energy-acquires-altair-renewable-fuel-assets-in-california; Alt/Air World Energy Paramount, CEQAnet Web Portal, Governor's Office of Planning and Research (June 2020), https://ceqanet.opr.ca.gov/2020069013/2.

[254] Delek US Holdings, Inc, Delek US Holdings Announces Closing of Bakersfield Refinery Sale, Global Newswire (May 07, 2020). https://www.globenewswire.com/news-release/2020/05/07/2029947/0/en/Delek-US-Holdings-Announces-Closing-of-Bakersfield-Refinery-Sale.html (accessed Dec 8, 2021).

[255] Comments by Biofuelwatch et al dated December 17, 2021 concerning Martinez refinery renewable fuels project, File No. CDLP20-02046.

[256] Portner 2021, pp. 18-19, 28-29, 53-58.; Searchinger, 2008.

industry,[257] the environmental justice community,[258] as well as within the biofuel industry[259] itself. Currently planning a biofuel refinery conversion in Bakersfield, Global Clean Energy Holdings, Inc. remarked in its SEC 10-K filing, "[t]he greatest challenge to the wide adoption of [HEFA] renewable fuels is the limited availability of the plant oils and animal fats that are the feedstock of [HEFA] renewable fuels."[260] Given these constraints, a single biofuel conversion project of this magnitude could dramatically induce land use changes and makes the need for a cumulative analysis all the more dire.

The U.S. biofuel industry already consumes a significant portion of existing farm production of oils and animal fats. As shown in Table 8, as of fall 2021, there are eight operating renewable biofuel facilities and 75 biodiesel facilities, with a combined potential consumption of 235,000 barrels per day, or 3.6 billion gallons per year of lipid feedstocks. Meanwhile, the U.S. currently produces 372,000 barrels per day of oils and animal fats for all uses. Thus, at full capacity, these existing projects could consume up to 63% of existing U.S. production. Meanwhile, between these projects, the feedstock actually consumed (which is less than the amount theoretically possible under full production capacity) represented 31% of total U.S. production. *See* Table 8.

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[257] Kelly, S., U.S. renewable fuels market could face feedstock deficit, *Reuters* (Apr. 8, 2021), https://www.reuters.com/article/us-usa-energy-feedstocks-graphic/us-renewable-fuels-market-could-face-feedstock-deficit-idUSKBN2BW0EO (accessed Dec 8, 2021).

[258] *See e.g.*, Press Release, California Environmental Justice Alliance, IPCC Report Shows Urgent Need to Zero Out Fossil Fuels, Reduce Direct Emissions (Aug. 17, 2021), https://caleja.org/wp-content/uploads/2021/08/CEJA_IPCC_2021-3.pdf; Rachel Smolker, *Bioenergy* in Hoodwinked in the Hothouse: Resist False Solutions to Climate Change, Biofuelwatch, Energy Justice network, Global Alliance for Incinerator Alternatives, ETC Group, Global Justice Ecology Project, Indigenous Climate Action, Indigenous Environmental Network, Just Transition Alliance, La Via Campesino, Movement Generation Justice and Ecology Project, Mt. Diablo Rising Tide, Mutual Aid Disaster Relief, North American Megadam Resistance Alliance, Nuclear Information and Resource Service, Rising Tide North America, Shaping Change Collaborative 19-20 (3d ed. Apr. 2021), https://d5i6is0eze552.cloudfront.net/documents/Destination-deforestation_Oct2019.pdf.

[259] Nickle et al., 2021. Renewable diesel boom highlights challenges in clean-energy transition (Mar 3, 2021), *Reuters*. https://www.reuters.com/article/us-global-oil-biofuels-insight-idUSKBN2AV1BS.

[260] Global Clean Energy Holdings, Inc., Annual Report (Form 10-K) April 13, 2021, https://www.sec.gov/Archives/edgar/data/748790/000152013821000195/gceh-20201231_10k.htm#a003_v1.

Table 8: US Biofuel Source-Specific Feedstock Production & Consumption

MM t/y: Million Metric tons per year **b/d**: barrel, 42 U.S. gallons, per day

Lipid Type	All-Use US Production		Consumed in US As Biofuel Feedstock		
	Volume (b/d)[a,b]	Mass (MM t/y)[a,b]	Volume (b/d)[c]	Mass (MM t/y)[c]	As Percentage of US Production (%)
Poultry Fat	22,573	1.1	1,455	0.07	6%
Tallow	51,386	2.68	3,312	0.17	6%
White Grease	13,420	0.75	4,793	0.27	36%
Yellow Grease	18,272	0.96	11,928	0.63	65%
Canola oil	14,425	0.77	10,604	0.56	74%
Corn oil	49,201	2.62	15,249	0.81	31%
Soybean oil	202,672	10.77	66,113	3.51	33%
All Lipids	**371,948**	**19.65**	**112,544**	**6.03**	**31%**

a. US production for poultry fat, tallow (specifically inedible tallow, edible tallow, and technical tallow), white grease (specifically lard and choice white grease), and yellow grease taken from USDA estimates for 2017 through 2020. USDA National Agricultural Statistics Service "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks" Annual Summaries for 2017 through 2020. National Agricultural Statistics Service, "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks Annual Summary", 2017 through 2020, https://usda.library.cornell.edu/concern/publications/mp48sc77c. (accessed Dec. 14, 2021). Volume to mass conversions use specific gravities of 0.84, 0.96, and 0.91 for poultry fat, white grease, and yellow grease, respectively. **b.** Production for canola oil, corn oil (which includes distillers' corn oil), and soybean oil taken from USDA Oil Crops Yearbook Tables 5, 26, and 33, averaged from Oct. 2016 to Sept. 2020. USDA, Oil Crops Yearbook Tables 5, 26, and 33, Mar. 26, 2021, https://www.ers.usda.gov/data-products/oil-crops-yearbook/ (accessed Dec. 14, 2021). Volume to mass conversions use specific gravities of 0.914, 0.916, and 0.916 for canola oil, corn oil, and soybean oil, respectively. **c.** Lipid feedstocks consumed for biodiesel production are averages of 2018 through 2020 taken from EIA Monthly Biodiesel Production Report, Table 3. EIA, Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Biofuel feedstock estimates for canola oil are an average of 2019 and 2020 data because 2018 data were suppressed. Volume to mass conversions use specific gravities identified in a. and b.

In recent years, numerous additional biofuel projects have been proposed, with several already under construction. A review of news publications and other reports found 16 future projects either proposed, under construction, or under active consideration by refineries, in addition to the Marathon proposal. In total, these projects could triple the total amount of lipids consumed to a total capacity of 693,000 barrels per day, which would drastically exceed current, total U.S. lipid production. At full production these past and future projects would represent nearly double the entire nation’s output. As a result, it is foreseeable that cumulatively, these projects will require massive increases in domestic oil crop production or foreign imports, either of which will be associated with massive environmental and climate impacts from land use changes.

Table 9: Current and Future Lipid-Based US Biofuel Projects

b/d: barrel, 42 U.S. gallons, per day

Refinery	Site Location	Status	Lipid Feedstock Capacity (b/d)	Lipid Feedstock Capacity As Percentage of US Lipid Supply (%)
East Kansas Agri-Energy Renewable Diesel	Garnett, KS	Operational	206	0.1%
Dakota Prairie Refining LLC	Dickinson, ND	Operational	13,183	3.5%
Diamond Green Diesel LLC	Norco, LA	Operational	23,139	6.2%
REG-Geismar LLC	Geismar, LA	Operational	6,866	1.8%
Wyoming Renewable Diesel CO	Sinclair, WY	Operational	8,033	2.2%
Altair Paramount LLC	Paramount, CA	Operational	2,884	0.8%
American GreenFuels	Encinitas, CT	Operational	2,403	0.6%
Down To Earth Energy LLC	Monroe, GA	Operational	137	0.0%
World Energy Rome	Rome, GA	Operational	1,373	0.4%
Cape Cod Biofuels Inc	Sandwich, MA	Operational	69	0.0%
Maine Bio-Fuel Inc	Portland, ME	Operational	69	0.0%
Blue Ridge Biofuels LLC	Newton, NC	Operational	137	0.0%
Renewable Fuels by Peterson	North Haverhill, NH	Operational	549	0.1%
World Energy Harrisburg LLC	Camp Hill, PA	Operational	1,305	0.4%
Lake Erie Biofuels LLC	Erie, PA	Operational	3,090	0.8%
Newport Biodiesel Inc	Newport, RI	Operational	481	0.1%
Southeast Biodiesel/South Carolina LLC	Charleston, SC	Operational	343	0.1%
Reco Biodiesel LLC	Reco Biodiesel, VA	Operational	137	0.0%
Virginia Biodiesel Refinery LLC	Kilmarnock, VA	Operational	343	0.1%
AG Processing - Algona	Algona, IA	Operational	5,218	1.4%
AG Processing - Sgt Bluff	Sgt Bluff, IA	Operational	5,218	1.4%
REG - Newton	Newton, IA	Operational	2,609	0.7%
REG - Ralston	Ralston, IA	Operational	3,364	0.9%
Lva Crawfordsville Biofuel LLC	Crawfordsville, IA	Operational	687	0.2%
Cargill Inc	Iowa Falls, IA	Operational	3,845	1.0%
Iowa Renewable Energy LLC	Washington, IA	Operational	2,472	0.7%
Reg - Mason City	Mason City, IA	Operational	2,609	0.7%
Western Dubuque Biodiesel LLC	Farley, IA	Operational	2,472	0.7%
Western Iowa Energy LLC	Wall Lake, IA	Operational	3,090	0.8%
Adkins Energy LLC	Lena, IL	Operational	275	0.1%
REG - Danville	Danville, IL	Operational	3,433	0.9%
REG - Seneca	Seneca, IL	Operational	5,218	1.4%

Incobrasa Industries Ltd	Gilman, IL	Operational	3,021	0.8%
Alternative Fuel Solutions LLC	Huntington, IN	Operational	206	0.1%
Integrity Bio-Fuels LLC	Morristown, IN	Operational	343	0.1%
Louis Dreyfus Agricultural Industries LLC	Claypool, IN	Operational	6,797	1.8%
Cargill Inc	Wichita, KS	Operational	4,120	1.1%
Darling Ingredients Inc	Butler, KY	Operational	137	0.0%
Owensboro Grain Biodiesel LLC	Owensboro, KY	Operational	3,708	1.0%
Adrian Lva Biofuel LLC	Adrian, MI	Operational	1,030	0.3%
Thumb Bioenergy LLC	Sandusky, MI	Operational	-	-
Ever Cat Fuels LLC	Isanti, MN	Operational	206	0.1%
Minnesota Soybean Processors	Brewster, MN	Operational	2,472	0.7%
Reg - Albert Lea	Albert Lea, MN	Operational	3,158	0.8%
AG Processing - St. Joseph	St. Joseph, MO	Operational	2,884	0.8%
Deerfield Energy LLC	Deerfield, MO	Operational	3,433	0.9%
Ethos Alternative Energy of Missouri LLC	Lilborne, MO	Operational	343	0.1%
Seaboard Energy Marketing St Joseph	St. Joseph, MO	Operational	2,403	0.6%
Mid-America Biofuels, LLC	Mexico, MO	Operational	3,433	0.9%
Natural Biodiesel Plant LLC	Hayti, MO	Operational	343	0.1%
Paseo Cargill Energy LLC	Kansas City, MO	Operational	3,845	1.0%
Archer-Daniels-Midland Company	Velva, ND	Operational	5,836	1.6%
Cincinnati Renewable Fuels LLC	Cincinnati, OH	Operational	6,248	1.7%
Seaboard Energy Marketing Inc	Guymon, OK	Operational	2,609	0.7%
Bioenergy Development Group LLC	Memphis, TN	Operational	2,472	0.7%
REG - Madison	De Forest, WI	Operational	1,923	0.5%
Walsh Bio Fuels LLC	Mauston, WI	Operational	343	0.1%
Hero Bx Alabama LLC	Moundville, AL	Operational	1,373	0.4%
Delek Renewables Corp	Crossett, AR	Operational	1,030	0.3%
Futurefuel Chemical Company	Batesville, AR	Operational	4,120	1.1%
Solfuels USA LLC	Helena, AR	Operational	2,746	0.7%
Delek US	New Albany, MS	Operational	824	0.2%
Scott Petroleum Corporation	Greenville, MS	Operational	1,167	0.3%
World Energy Natchez LLC	Natchez, MS	Operational	4,944	1.3%
REG - Houston	Seabrook, TX	Operational	3,639	1.0%
World Energy Biox Biofuels LLC	Galena Park, TX	Operational	6,179	1.7%
Delek Renewables LLC	Clerburne, TX	Operational	824	0.2%
Eberle Biodiesel LLC	Liverpool, TX	Operational	-	-
Global Alternative Fuels LLC	El Paso, TX	Operational	1,030	0.3%
Rbf Port Neches LLC	Houston, TX	Operational	9,887	2.7%

Sabine Biofuels II LLC	Houston, TX	Operational	2,060	0.6%
Alaska Green Waste Solutions LLC	Anchorage, AK	Operational	-	-
Grecycle Arizona LLC	Tucson, AZ	Operational	137	0.0%
Crimson Renewable Energy LP	Bakersfield, CA	Operational	1,923	0.5%
American Biodiesel Inc	Encinitas, CA	Operational	1,373	0.4%
Imperial Western Products Inc	Coachella, CA	Operational	824	0.2%
New Leaf Biofuel LLC	San Diego, CA	Operational	412	0.1%
Simple Fuels Biodiesel	Chilcoot, CA	Operational	69	0.0%
Big Island Biodiesel LLC	Keaau, HI	Operational	412	0.1%
Sequential-Pacific Biodiesel LLC	Salem, OR	Operational	824	0.2%
REG - Grays Harbor	Hoquiam, WA	Operational	7,347	2.0%
Marathon[a]	Dickinson, ND	Operational	12,631	3.4%
Camber Energy[b]	Reno, NV	Operational	2,952	0.8%
All Operational Projects			**235,298**	**63.3%**
Global Clean Energy Holdings[c]	Bakersfield	Under Construction	15,000	4.0%
HollyFrontier Corp[d]	Artesia, NM	Under Construction	8,583	2.3%
HollyFrontier Corp[e]	Cheyenne, WY	Under Construction	6,179	1.7%
Diamond Green Diesel[f]	Port Arthur, TX	Under Construction	36,390	9.8%
Diamond Green Diesel[g]	Norco, LA	Under Construction	27,464	7.4%
CVR[h]	Wynnewood, OK	Proposed	6,866	1.8%
Ryze Renewables[i]	Las Vegas, NV	Under Construction	7,894	2.1%
NEXT Renewable Fuels Oregon[j]	Clatskanie, OR	Proposed	50,000	13.4%
Renewable Energy Group[k]	Geismar, LA	Under Construction	17,165	4.6%
World Energy[l]	Paramount, CA	Proposed	21,500	5.8%
Grön Fuels LLC[m]	Baton Rouge, LA	Proposed	66,312	17.8%
PBF[n]	Chalmette, LA	Proposed	24,722	6.6%
Calumet[o]	Great Falls, MT	Proposed	12,631	3.4%
Seaboard Energy[p]	Hugoton, KS	Under Construction	6,842	1.8%
Chevron[q]	El Segundo, CA	Under Construction	10,526	2.8%
CVR Energy[r]	Coffeyville, KS	Under Consideration	11,578	3.1%
Phillips 66[s]	Rodeo, CA	Proposed	80,000	21.5%
Marathon[t]	Martinez, CA	Proposed	48,000	12.9%
All Future Projects			**457,652**	**123.0%**

All Operational & Future Projects	**692,950**	**186.3%**

All projects from EIA 2021 "U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity" and "U.S. Biodiesel Plant Production Capacity" reports unless otherwise noted. “-” indicates that capacity data was suppressed in the EIA data. EIA, U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity, Petroleum Reports, Sept. 3, 2021, https://www.eia.gov/biofuels/renewable/capacity/renewablescapacity.xlsx (accessed Dec. 14, 2021).; EIA, U.S. Biodiesel Plant Production Capacity, Petroleum Reports, September 3, 2021, https://www.eia.gov/biofuels/biodiesel/capacity/biodieselcapacity.xlsx (accessed Dec. 14, 2021). **a.** Frohlke, U. 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Chevron expands renewable fuels output with more lower carbon business spending, S&P Global, Sep. 14, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/agriculture/091421-chevron-expands-renewable-fuels-output-with-more-lower-carbon-business-spending (accessed Dec. 14, 2021). **r.** CVR Energy selects Honeywell technology for Coffeyville refinery, Dec. 9, 2021, http://biomassmagazine.com/articles/18550/cvr-energy-selects-honeywell-technology-for-coffeyville-refinery (accessed Dec 14, 2021). **s.** Rodeo Renewed DEIR at 3-23 **t.** Marathon Martinez DEIR at 2-15 **u.** Feedstock capacities calculated assuming a feed-to-product mass ratio of 80.9% per Pearlson et al. (2013) for maximum distillate production, an average lipid feedstock specific gravity of 0.916 (that of soybean oil), and an average product specific gravity of 0.78 (that of renewable diesel). **v.** Total US yield of lipids taken from Table 9.

Thus, while the impacts of either project standing alone on agricultural resources and land use would be large, the combined impact of the two projects together could be catastrophic in scale – even more so when other existing and planned projects are considered in the cumulative impacts mix. Among other things, this level of market disruption would greatly increase that likelihood that other types of fungible food crop oils – including palm oil – would start to replace the dwindling supply of soy and other food crop oils, with attendant destructive impacts. The sheer amount the land required to grow food crop oils for existing and projected biofuel projects domestically indicates dramatic land use changes will inevitably occur at a global scale. Despite the novelty of this type of refinery conversion in California, even just the national data shows the Project is entering a large biodiesel market which has already contributed to the significant indirect land use changes documented in Section IV above.

B. The DEIR Should Have Analyzed the Cumulative Impact of California Biofuel Production on the State's Climate Goals[261]

As discussed in Section VI, large-scale biofuel production is incompatible with California's climate goals, which contemplate large-scale electrification via BEVs, and a phase-out of combustion fuel. That impact cannot be fully disclosed, measured, and analyzed, however, without looking at the cumulative impact of all of the biofuel production existing or contemplated in the state. The DEIR erred in not undertaking that analysis.

Such analysis would reveal that, in fact, current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by this Project, the Marathon, AltAir, and the Global Clean Energy (GCE) projects for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.[262] If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0-1.5 billion gal./y in state climate pathways.

Further HEFA biofuels growth could also exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up, and refiners would be highly incentivized to protect those otherwise stranded assets (Chapter 1).

Chart 5 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are

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[261] Additional support for this section is provided in Karras, 2021a.

[262] Supporting Material Appendix for 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, www.energy-re-source.com; Application for Authority to Construct Permit and Title V Operating Permit Revision for Rodeo Renewed Project: Phillips 66 Company San Francisco Refinery (District Plant No. 21359 and Title V Facility # A0016); Prepared for Phillips 66 by Ramboll US Consulting, San Francisco, CA. May 2021; Initial Study for: Tesoro Refining & Marketing Company LLC—Marathon Martinez Refinery Renewable Fuels Project; received by Contra Costa County Dept. of Conservation and Development 1 Oct 2020; April 28, 2020 Flare Event Causal Analysis; Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758; report dated 29 June, 2020 submitted by Marathon to the Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports ; Paramount Petroleum, AltAir Renewable Fuels Project Initial Study; submitted to City of Paramount Planning Division, 16400 Colorado Ave., Paramount, CA. Prepared by MRS Environmental, 1306 Santa Barbara St., Santa Barbara, CA; Brelsford, R. Global Clean Energy lets contract for Bakersfield refinery conversion project. Oil & Gas Journal. 2020. Jan.9, 2020.

stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 5.

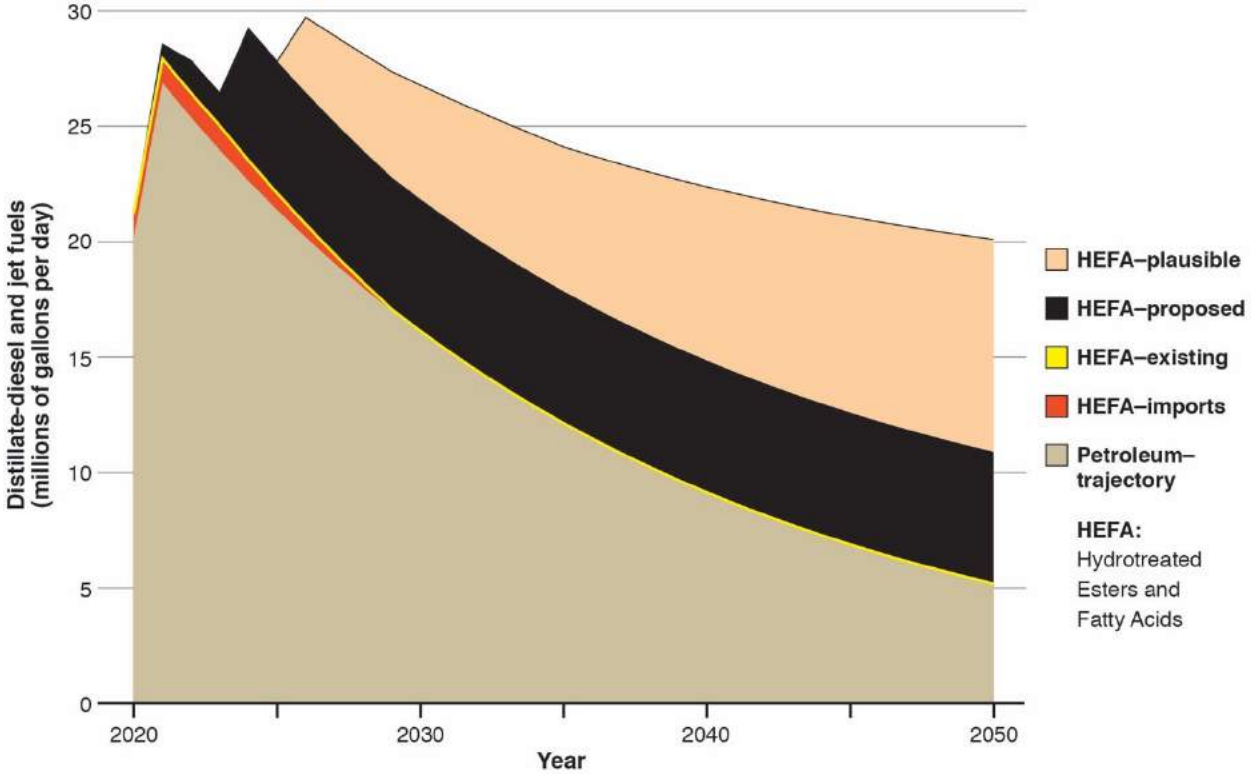

Chart 5: Future HEFA Biofuel Growth Trajectory

4. Combustion fuels additive potential of HEFA diesel and jet production in California. As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillate-diesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lower-carbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs. **Petroleum-trajectory** for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J**:**G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020-2021 reflect the expected partial rebound from COVID-19. **HEFA-imports** and **HEFA-existing** are the mean D+J "renewable" volumes imported, and refined in the state, respectively, from 2017-2019. The potential in-state expansion shown could squeeze out imports. **HEFA-proposed** is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively. **HEFA-plausible:** as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways, and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market[i] anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H_2 demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J **:** D product slate ratio growing from 1: 5.3 to 1: 2, during 2025–2035. For conceptual analysis *see* Karras, 2021a; for data and methodological details see Karras, 2021a Table A7.[263]

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[263] Supporting Material Appendix for 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, www.energy-re-source.com.

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.[264] HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6-3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.[265] This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market — a fuel share that HEFA refiners would then be motivated to retain.

The scenario shown in Chart 5 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.[266] HEFA growth by 2025 in the Chart 5 scenario is less than half of those plans. Had the DEIR considered that 5.2 billion gallon/year estimate by California Energy Commission staff,[267] for example, the County could have found that the Project would contribute to exceeding the state climate pathway constraint discussed in Section V of 0.5–0.6 and 0.8–0.9 billion gallons/year total HEFA jet fuel, and HEFA diesel combustion, respectively, based on that fact alone. Additionally, State climate pathways reported by Mahone et al. replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 5, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets.

C. The DEIR Did Not Adequately Disclose and Analyze Cumulative Marine Resources Impacts

There is currently a boom in proposals for biofuel conversions. Unlike existing fossil fuel refining, there is little existing transportation infrastructure for biofuel feedstocks, so, as with the Project, much of that transportation will take place via ship. This means that there will be cumulative impacts to marine resources that have not been adequately evaluated in the DEIR. For example, increases in feedstock demand will implicate economic and transportation impacts to marine resources all over the world.

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[264] *Id.*

[265] Mahone et al., 2020a. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board, DRAFT: August 2020; Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.arb.ca.gov/sites/default/files/2020-08/e3_cn_draft_report_aug2020.pdf

[266] Schremp (2020). Transportation Fuels Trends, Jet Fuel Overview, Fuel Market Changes & Potential Refinery Closure Impacts. BAAQMD Board of Directors Special Meeting, May 5 2021, G. Schremp, Energy Assessments Division, California Energy Commission. In Board Agenda Presentations Package; https://www.baaqmd.gov/-/media/files/board-of-directors/2021/bods_presentations_050521_revised_op-pdf.pdf?la=en

[267] *Id.*

In 2017 Phillips 66 proposed a marine terminal expansion. According to the Project Description for that project, it was to

> modify the existing Air District permit limits to allow an increase in the amount of crude and gas oil that may be brought by ship or barge to the Marine Terminal at the Phillips 66 Company (Phillips 66} San Francisco Refinery in Rodeo, California (Rodeo Refinery). The refinery processes crude oil from a variety of domestic and foreign sources delivered by ship or barge at the Marine Terminal and from central California received by pipeline. The Proposed Project would allow the refinery to receive more waterborne-delivered crude and gas oil, and thereby to replace roughly equivalent volumes of pipeline-delivered crudes with waterborne-delivered crudes. However, the Proposed Project would not affect the characteristics of the crude oil and gas oil the refinery is able to process.
>
> The proposed increase in offloading and the additional ship and barge traffic necessitates modification of Phillips 66's existing Permit to Operate and the Major Facility Review (Title V) Permit, which was issued by the Air District to the Phillips 66, San Francisco Refinery (BAAQMD Facility #A0016). Approval of the proposed air permit modifications would be a discretionary action by the Air District, requiring CEQA review (BAAQMD Regulation 2-1-310).

Phillips 66 Marine Terminal Permit Revision Project, Notice of Preparation, June 2017, p. 2. The final EIR must evaluate past proposals such as the 2017 marine terminal expansion proposal, to determine whether there are cumulative impacts and whether those proposals are likely to be approved.

The record for BAAQMD’s analysis of the 2017 project proposal should be incorporated into the record for the current CEQA review.

X. THE DEIR SHOULD HAVE MORE FULLY ADDRESSED HAZARDOUS CONTAMINATION ISSUES ASSOCIATED WITH CONSTRUCTION AND DECOMMISSIONING

The DEIR failed to adequately address the interrelated issues of site decommissioning and contamination hazards. The Refinery site is heavily contaminated, which gives rise to issues concerning both how decommissioned portions of the refinery will be addressed, and how Project construction and operation may affect ongoing remediation and monitoring activities. Additionally, given the likely short and definably finite commercial lifetime of the Project, the DEIR should have evaluated the impact of full site decommissioning.

A. The DEIR Inadequately Evaluate Project Impacts on Hazardous Waste Cleanup Operations

The fails to disclose and analyze information concerning the multiple cleanup orders that have been issued for the site, and how Project construction may impact the cleanup work. The general overview of specific water quality remediation projects (DEIR at 4.10-356) is an incomplete description of such activities. Described below are specific measures taken by agencies to address hazardous contamination at the Refinery, which should have been addressed.

The Department of Toxic Substances Control (DTSC) is monitoring two areas under Facility EPA ID Number: CAD009108705 affected by hazardous contamination. The first is the Primary Basin, whose latest Post Closure Facility Permit was effective February 21, 2012 and will expire February 20, 2022.[268] The DTSC has also placed deed restrictions on contaminate areas at the Refinery, banning land use for residences, hospitals, schools, and day cares.[269].

Additionally, the San Francisco Bay Regional Water Quality Control Board (Water Board) is extensively addressing hazardous contaminants affecting water quality, but the DEIR only references at a high level (DEIR 4.10-356). The Water Board has two active correction actions with the refinery: a waste discharge requirement and a site cleanup requirement.[270]

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[268] The Primary Basin is located in the southern portion of the facility east of the Unit 100 wastewater facility. The permit will allow the facility to conduct closure activities, groundwater monitoring, liner and leachate collection/leak detection system inspection and maintenance, and emergency storage. The second is the Land Treatment Area (LTA) whose latest Post Closure Facility Permit was effective 1/9/17 and will expire 1/8/27. The LTA is in the southern portion of the facility and received hazardous wastes between 1976 and 1983. The LTA has been a US EPA Post-closure permit since 1989. The permitted activities are conduct post closure activities, groundwater monitoring, soil sampling, inspection and maintenance of the wells and cap/vegetative cover. See Hazardous Waste Post Closure Facility Permit Land Treatment Area issued to Phillips 66 Co., effective Date January 9, 2017; Hazardous Waste Post Closure Facility Permit, Primary Basin, issued to ConocoPhillips, Effective Date: February 21, 2012.

[269] The DTSC has filed three such deed restrictions all on 8/26/19. Two relate to Post-Closure Permits and the third is joint effort with the Water Board on surface and subsurface hazardous wastes. The first one is for 1.37 acres of the Primary Basin. The second one is for 6.4 acres of the LTA. The third one is for 1.06 acres of the Former Container Storage Unit (FCSU). Per a March, 1996 agreement with the Water Board, the DTSC would oversee the closures of the surface containment structures (asphalt pads, concrete slabs) and the Water Board would address the subsurface issues as part of Inactive Waste Site 6C correction action process. A Closure Certification Report was submitted to DTSC on 10/31/11 and approved 7/31/12(noted in recorded deed) noting that the certification was conditioned on recording of a land use covenant. See Closure Certification Report, Former Container Storage Unit ConocoPhillips San Francisco Refinery Rodeo, California, EPA ID No. 009108705, October 31, 2011; Covenant to Restrict Use of Property Environmental Restriction, Contra Costa County Assessor's Parcel No. 357-300-005, Primary Basin within the Phillips 66 Company San Francisco Refinery (Rodeo, California), EPA ID No. CAD009108705, DTSC Site Code: 200203; Covenant to Restrict Use of Property Environmental Restriction Contra Costa County Assessor's Parcel No. 358-010-008, Land Treatment Area within the Phillips 66 Company San Francisco Refinery (Rodeo, California), EPA ID Number CAD009108705, DTSC Site Code: 200203.

[270] Both these requirements are conditioned by Final Revised Groundwater Self-Monitoring Plan (SMP) dated April 29, 2015. The SMP reviewed the then current groundwater monitoring and reporting requirements that were included in the Waste Discharge Requirements (WDR) Order No. R2-2005-0026, adopted by the Water Board in June 2005, and referred to in the SCR Order No. R2 2006-0065 adopted by the Water Board in October 2006. In accordance with Task 11 of the San Francisco Bay Regional Water Quality Control Board (Water Board) Site

These actions involve an extensive monitoring program associated with both the DTSC and the Water Board cleanup actions.[271]

Of particular note is that the Water Board identified an issue with tar seeps at the Refinery site. [272] The investigation of the area for tar seep was carried out between 2016 and 2019 and the remediation in 2020. Approximately 127 metal drums and wood barrels were removed. A total of approximately 601.5 tons of waste soil and tar were excavated. The waste was characterized as Class II non-hazardous material, and was transported offsite.[273]

All of these historic and ongoing actions should have been evaluated in sufficient depth to determine whether Project construction and operation has the potential to negatively impact them, either by disturbing contaminated areas or interfering with remediation and monitoring.

With regard to contaminated areas, the tar seep issue illustrates the critical importance of assessing the impact on these areas of excavation and movement of material that will be involved in conversion construction. Historically, numerous tar seeps have been observed on the pavement surface throughout the areas surrounding the warehouse building and the laboratory building. Although the tar is firm and immobile during the colder months, elevated ambient temperatures

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Cleanup Requirements (SCR) Order No. R2-2006-0065, the SMP realigned the groundwater-monitoring program to the current site conditions.

[271] The SMP evaluated the current groundwater monitoring program at the site includes wells associated with the WDR, the SCR, and the DTSC Permits, in addition to wells associated with various voluntary investigation and evaluations programs at the refinery that are not specifically defined under a regulatory order, directive, or permit. Wells associated with the WDR are generally monitored under a detection-monitoring program, intended to detect indications of a potential release from the subject waste management unit. Wells associated with the SCR are monitored under a corrective action evaluation program, intended to evaluate the effectiveness of the specific corrective action. See California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2006-0065, Site Cleanup Requirements and Recission of Order No. 93-046 for ConocoPhillips Company San Francisco Refinery, October 11, 2006; California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2005-0026, Updated Waste Discharge Requirements and Rescission of Order No. 97-027 for ConocoPhillips Company San Francisco Refinery, June 15, 2005.

[272] Based on the SMP, the Water Board and Phillips updated the WDR to R2-2015-0046 and the SCR to R2-2018-0014 with the updates to monitoring hazardous waste and groundwater. SCR R2-2018-0014 contained several mandatory tasks that needed special attention. These included Main Interceptor Trench (MIT) Alignment C Extension Completion Report, A-E Gap Hydraulic Containment System Completion Report, Area 6 FPLH Recoverability Evaluation Report, and the Tar Seep Area Investigation Report. California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2018-0014, Updated Site Cleanup Requirements and Recission of Order Nos. R2-2006-0065 and R2-2012-0081 for Phillips 66 Company San Francisco Refinery, April 13, 2018; California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2015-0046, Updated Waste Discharge Requirements and Rescission of Order No. R2-2005-0026 for Phillips 66 Company San Francisco Refinery, November 23, 2015.

[273] The waste tar drums, and impacted soil were transported and disposed of offsite at Republic Services' Keller Canyon landfill in Pittsburg, California. A new utility duct-bank was installed around the perimeter of the excavation from the existing power pole then south to the laboratory building. After the duct-back was installed, the cables in the two pre-existing utility duct-banks were taken out of service and removed. Two unanticipated pipeline segments were encountered, removed or abandoned in-place during the excavation. Along the southeastern excavation area, approximately 30 linear feet of 8-inch diameter wooden-stave storm drainpipe removed. A metal 10-inch diameter pipe segment, buried approximately 6 feet bgs, capped in-place with concrete. As you can from the remediation efforts, there is risk to any remediation to any area of the refinery.

during the summer months soften the tar, causing it to seep and expand vertically via viscous flows to the ground surface and spread by gravity, adhering to the wheels of vehicles, and the shoes of pedestrians.[274] A similar problem of buried contamination arose when a rusted 55 gallon drum was found in 2021 around Tank 302 when the Main Interceptor Trench was being upgraded per Task 1 of R2-2018-0014. These excavation risks should be explained more clearly in the DEIR[275]

With regard to monitoring activities, the DEIR inadequately describes the potential impact of the new Sulfur Treatment Unit (STU) and Pre-Treatment Unit(PTU) will have on existing Inactive Waste Unites (IWS) and current monitoring of wastes and groundwater. Figure 3.2 of the DEIR shows the positions of the new STU and PTU units and where the three storage tanks will be torn down. Figures 4 and 6 of SCR-R2-20018-0014 seem to indicate that the STU and PTU will be built over IWS 4. The DEIR should have addressed the potential impacts of this construction in IWS 4, and proposed mitigation to minimize disturbance. Similarly, the DEIR did not address impacts of Project activities on monitoring associated with the Carbon Plant, which is also under a WDR. [276]

The DEIR should have disclosed in detail all of these historic and ongoing cleanup and monitoring operations, and described the Project's impact on them.. Without such disclosure, the DEIR's cursory conclusion that construction and operation activities will not impact them is unsupported by substantial evidence. DEIR at 4.9-326-327; 339-340.

B. The DEIR Should Have More Fully Evaluated Impacts of Partial and Complete Decommissioning

The DEIR addresses decommissioning at the Project site only with respect to infrastructure that would not be used in connection with the Project, including the pipeline sites, Carbon Plant, and Santa Maria facility; and construction of new Project infrastructure. DEIR at 3-31, 4.9-326-327 and 339-340. However, as discussed in Section II, the foreseeable likelihood is that biofuel demand in California will wane significantly within the relatively near term as

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[274] Letter dated September 25,2020 to Ross Steenson from Christopher M. Swartz re Tar Drums Removal Summary Report Phillips 66 San Francisco Refinery, Rodeo, California
Task 7, Site Cleanup Requirements Order No. R2—2018—0014 CRWQCB—SFB File No. 2119.1051.

[275] Letter dated June 9, 2021 from Christopher M. Swartz re Tank 302 GW Barrier System Construction - Buried Drum Removal Summary Report Site Cleanup Requirements Order No. R2-2018-0014 CRWQCB-SFB File No. 2119.1051.

[276] WDR R2-2008-0013 regulates stormwater at the Carbon Plant. The previous owner constructed the Basin System, consisting of two settling basins and a large surface impoundment, in 1983. The Basin System was designed to recover water used at the Facility, including 1) cooling tower blowdown water, 2) dust control water, and 3) storm water runoff; and recover coke fines. This water is recycled from the surface impoundment and used in Facility processes, in a closed loop system. Amendment R2-2013-0008 was added to update the self-monitoring system. The DEIR did not mention the risks to the groundwater by the removal and demolishing of the Carbon Plant. See California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2013-0008, Amendment of Waste Discharge Requirements Order No. R2-2008-0013 for Phillips 66 Company Rodeo Carbon Plant, March 13, 2013; California Regional Water Quality Control Board San Francisco Bay Region, Order No. R2-2008-0013, Updated Waste Discharge Requirements and Rescission of Order No. 98-038 for ConocoPhillips Company Contra Costa Carbon Plant, March 17, 2008.

California transitions to a zero-emissions transportation economy. As noted, Contra Costa County itself has signed a pledge to be "diesel free by '33." Accordingly, the realistic likelihood is that the Project's commercial life will be short. Thus, in order to fully inform that public regarding foreseeable impacts, and to guide the County's thinking about planning for the Project site's future, the DEIR should have examined the impacts of full decommissioning of the site (even though such full decommissioning was rejected as a Project alternative, DEIR at 5-9).

The DEIR, however, does not substantively evaluate decommissioning impacts at all – either with respect to the infrastructure it acknowledges will be decommissioned, or the remaining infrastructure whose decommissioning in the not-distant future is inevitable. The DEIR should have disclosed and analyzed the impact of decommissioning in both these scenarios. With respect to decommissioning envisioned as part of the Project, the DEIR notes that the Project "includes the cessation of operations at the Carbon Plant and of the crude handling units, sulfur recovery unit, reformer, and isomerization unit." The DEIR should specify what will be done with this equipment, and how Phillips 66 will address any site contamination associated with it.

With respect to the inevitable decommissioning of the entire Refinery, the DEIR should have addressed the high level of existing contamination, and disclosed and analyzed the impacts of addressing it upon full decommissioning. Various oil companies refined oil at the Rodeo site since 1896,[277] some 75 years before the environmental protection wave of the early 1970s, and through waves of toxic gasoline additives—tetraethyl lead and then MTBE, from the 1930s through the early 2000s—and refinery releases to land persist to this day. Today, evidence that refinery byproduct waste disposal continues on surrounding land is here for all to see, at the carbon plant, where toxics-laden petroleum coke particulates dust the surrounding soil.

XI. THE DEIR INADEQUATELY ADDRESSED THE PROJECT'S IMPACTS ON MARINE RESOURCES

Even if the DEIR's baseline is taken at face value, in spite of the lack of any evidence that purported baselines reflect the actual amount of refining occurring at the Facility, the Project contemplates a drastic increase in the amount of feedstock and other potential pollutants crossing through the marine terminal. The DEIR claims that current product received through the marine terminal is 35,000 bpd, while the completed Project contemplates 118,000 pbd, an over 300% increase. DEIR at xxii (Table ES-1). This is reflected in the drastic increase in the number of taker and barge trips documented in the DEIR, up to 361 visits per year, an increase of 121 tanker vessels and 71 barges over baseline.

The DEIR's No Project Alternative shows 170 ship and barge trips per year. DEIR xxvii (Table ES-2). This is not an accurate depiction of the average number of trips over the last few years, nor is it an accurate estimate of how many trips would be taken if this Project were not completed at all. Regardless, the contemplated increase in ship traffic in San Francisco Bay over what currently occurs cannot be understated, as it is truly massive.

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[277] *California Refinery History;* California Energy Commission: Sacramento, CA. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries/california-oil.

A. The Wharf Throughput Expansion Would Result in Significant Water Quality Impacts, With Attendant Safety Hazards

The water quality impacts from expansion of marine terminal operations must be thoroughly examined, from impacts associated with the extraction and/or production of feed stocks to the dilution of those feedstocks and shipment to other ports, through the loading process onto tankers and the shipping routes they take to San Francisco Bay, then to the unloading of those feedstocks and transport into the refinery, the separation and reuse or disposal of unused portions or diluents, the eventual shipment of refined or reused products to end markets, and finally through to impacts from the use of end products. This lifecycle analysis must take into account global effects such as climate change and ocean acidification, as well as local water quality impacts that could have serious consequences for the communities at production sites, ports, along the shipping routes, and near the actual Project site in Rodeo. This analysis must also disclose the extent to which unknowns exist, such as the lack of concrete information concerning effective marine spill cleanup methodologies for feedstocks and the environmental impacts of such spills, and evaluate the risks taken as a result of those unknowns.

Each tanker trip carries an added risk of a spill, as a reported 50% of large spills occur in open water.[278] The majority of spills, however, are less than 200,000 gallons, and most of these spills happen while in port.[279] Two types of tanker will likely be used to transport feedstocks to the Facility, coastal tankers, which can carry as much as 340,000 barrels of oil (14.3 million gallons), and coastal tank barges, which typically carry 50,000 to 185,000 barrels of oil, though newer models can carry as much as a coastal tanker. In fact, the DEIR itself states that the maximum capacity of a single ship calling at the terminal is 1 million barrels. DEIR 4.9-330. "Therefore, as tanker/barge volumes could range as high as 1 million barrels, a theoretical maximum spill size from a barge or tanker contents that is used for planning purposes in the USCG-required vessel response plans could range up to 1 million barrels (based on the largest tanker capacity)." DEIR 4.9-330 – 4.9-331. No rationale or explanation is given for the selection of the much lower 10,000-20,000-barrel spill as a worst-case scenario. DEIR 4.9-331. The final EIR must evaluate an actual worst-case scenario instead of the watered down version discussed in the DEIR.

California's 45-billion-dollar coastal economy has a lot to lose to a spill.[280] California commercial fisheries for instance, produced from 186-361 million pounds of fish from 2013-2015, at a value of 129-266 million dollars.[281] After the Costco Busan disaster spilled 53,000 gallons of oil into San Francisco Bay, the Governor closed the fishery, a significant portion of which was either contaminated or killed, closed more than 50 public beaches, some as far south as Pacifica, and thousands of birds died. All told that spill resulted in more than 73 million dollars in estimated damages and cleanup costs.[282]

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[278] The International Tanker Owners Pollution Federation (2016 spill statistics), p. 8.

[279] *Id.*

[280] *California Ocean and Coastal Economies*, National Ocean Economics Program (March 2015).

[281] Based on California Department of Fish and Wildlife and National Marine Fisheries Service data.

[282] *See, e.g., Incident Specific Preparedness Review M/V Cosco Busan Oil Spill in San Francisco Bay Report on Initial Response Phase*, Baykeeper, OSPR, NOAA, et al. (Jan. 11, 2008).

A DEIR evaluating the environmental impacts of expanding operations at the Phillips 66 Marine Terminal must take into account the increased risk of a spill into San Francisco Bay or at any other point along the route transport tankers and barges will take. "Any increase in risk is considered to be a significant impact." DEIR 4.9-320. However, the DEIR fails to evaluate impacts from the handling of hazardous materials along transportation corridors, and from the presence of hazardous materials along shorelines in the event of a spill. DEIR 4.9-322 ("No existing or proposed schools are located within 0.25 mile of the Rodeo Site or the Carbon Plant Site; therefore, no hazardous materials would be handled within 0.25 mile of an existing school. Therefore, no impact would occur"). The final EIR must remedy this error.

Uncertainty over how to clean up spills of feedstocks extends to the specific technology used for cleanup efforts. "The environmental impacts associated with oil spill clean-up efforts (e.g. mechanical or chemical) may increase the magnitude of ecological damage and delay recovery."[283] Recent surveys have not found any studies on the response of "trophic groups within eelgrass and kelp forest ecosystems to bitumen in the environment, or the impacts of different spill-response methods."[284]

> Operation of the Project could result in discharges into waters of the San Pablo and San Francisco Bays from vessels (barges and tankers) transporting feedstocks and blending stocks to, and refined products from, the Marine Terminal. At full operation, 201 tankers and 161 barges would call each year, an increase of approximately 113 percent over baseline. Therefore, potential impacts related to vessel spills would be significant.

DEIR 4.9-331. The final EIR must do more to evaluate these impacts.

There are additional mitigation measures that should be considered and included in the final EIR to help mitigate spill risk. First, all ships carrying feedstocks, petroleum products, or any other hazardous material that could spill into San Francisco Bay or any of the other waters along the Project's transport routes should be double-hulled. "Recent studies comparing oil spillage rates from tankers based on hull design seem to suggest that double hull tankers spill less than pre-MARPOL single hull tankers, double bottom tankers, and double sided tankers."[285] Second, incentives for vessel speed reductions, as well as documentation and tracking of vessel speeds, as detailed elsewhere in these comments, would also reduce spill risks. Finally, additional yearly funding for the study of feedstock spills, the impact of such spills, and the most effective cleanup and mitigation methodologies would also help mitigate this risk and should be included in the final EIR.

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[283] Green *et al.*, 2017.

[284] *Id.*

[285] *A Review of Double Hull Tanker Oil Spill Prevention Considerations*, Nuka Research & Planning Group, LLC. (Dec. 2009), p. 3, *available at* https://www.pwsrcac.org/wp-content/uploads/filebase/programs/oil_spill_prevention_planning/double_hull_tanker_review.pdf.

A recent spill at the Phillips 66 Marine Terminal serves as a warning of what could result from increased marine terminal operations. According to press reports, "BAAQMD issued two 'public nuisance' violations to Phillips 66 for its Sept. 20, 2016 spill, which leaked oil into the bay and sent an estimated 120 people to the hospital from fumes."[286] That spill, which occurred while the Yamuna Spirit was offloading at the Phillips 66 Marine Terminal in Rodeo, was responsible for more than 1,400 odor complaints and a shelter-in-place order for the 120,000 residents of Vallejo, in addition to the hospital visits already mentioned.[287] The DEIR disavows responsibility for this incident, claiming (in spite of BAAQMD's contrary finding) that "An investigation ruled out the Marine Terminal and the Rodeo Refinery as the source." DEIR 4.9-296.

Instead, the DEIR claims that

> A release at the Marine Terminal would not present a significant safety hazard to members of the public due to the separation distance from public receptor locations. Even for low-probability large spills from the Marine Terminal, it is anticipated that separation distance of the Marine Terminal from public areas would provide time to respond with warnings and access controls before the spill could spread to public areas, which would limit the potential for unsafe levels of exposure to hazardous constituents in the spilled product or thermal radiation from a fire. Therefore, impacts from a spill and subsequent fire at the Marine Terminal would be less than significant.

DEIR 4.9-330. 120 people who went to the hospital in Vallejo may disagree that a release from the terminal would not represent a significant safety hazard. Spill events are also high variance, in that they are relatively unlikely to occur, and high impact, in that the repercussions of such an event have the potential to cause extensive damage. Typical baseline analysis, therefore, is inappropriate. A baseline analysis that said there was no risk of tanker spills based on baseline data from the previous 3 years, for instance, would be clearly inadequate in hindsight after an event like the Exxon Valdez. So, too, here, spill risk in the final EIR must be calculated and mitigated based on the worst case scenario, not on a baseline compiled over recent years that do not include any major oil spills.

In light of these concerns, Contra Costa must consider an independent study on feedstock cleanup, the adequacy of existing cleanup procedures and the need for additional cleanup and restitution funds, and increased monitoring for water and air quality impacts to communities surrounding the Project, whether those communities are located in the same county or not. Furthermore, the Bay Area Air Quality Management District should be considered as a responsible agency.

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[286] Katy St. Clair, "Supervisor Brown says 'no way' to proposed Phillips 66 expansion," Times-Herald (Aug. 5, 2017), *available at* http://www.timesheraldonline.com/article/NH/20170805/NEWS/170809877; *see also* Ted Goldberg, "Refinery, Tanker Firm Cited for Fumes That Sickened Scores in Vallejo," KQED News (June 16, 2017), *available at* https://ww2.kqed.org/news/2017/06/16/refinery-tanker-firm-cited-for-fumes-that-sickened-scores-in-vallejo/; Ted Goldberg, "Phillips 66 Seeks Huge Increase in Tanker Traffic to Rodeo Refinery," KQED News (July 27, 2017) (*available at* https://ww2.kqed.org/news/2017/07/27/phillips-66-seeks-big-increase-in-tanker-traffic-to-rodeo-refinery/.

[287] Ted Goldberg, "Refinery, Tanker Firm Cited for Fumes That Sickened Scores in Vallejo," *id.*

As pointed out by California State Senator Bill Dodd, it is vital that the causes of this spill be thoroughly investigated and a determination made on how such a spill can be prevented in the future.[288] Such an investigation must be completed before any additional ships are authorized to use the same marine terminal where the spill was reported. Without a thorough report on past spills that includes a description of what happened and how such accidents can be prevented in the future, the DEIR will not be able to adequately evaluate the Project's potential environmental impacts.

Additional National Pollutant Discharge Elimination System ("NPDES") effluent criteria may be needed, a possibility which must be—but is not—evaluated in the DEIR. Foreseeable spill rates from an increase in marine terminal activity might qualify as a discharge to waters of the United States because it is reasonably predictable that a certain number of spills will occur. With this and other water quality impacts in mind, the regional water board should at least be another responsible agency, if not the lead agency evaluating a permit to increase marine terminal operations. Furthermore, different feedstock may result in a change in the effluent discharged by the refinery under their existing NDPES permit, another reason why the regional water board should at least be a responsible party. The DEIR must evaluate an updated NPDES permit that reflects the changing feedstock that will result from the Project.

No reasonable mitigation or planning can be done with regard to the risk posed by the transport of feedstocks to the Phillips 66 refinery in Rodeo without specific information as to the chemical composition of the feedstocks being transported. Details on the types of feedstock expected to arrive on the tankers utilizing the Marine Terminal's expanded capacity must be part of the DEIR and must be made publicly available. It is irresponsible to conduct risk assessment and best practices for the handling of feedstocks without at least knowing exactly what the chemical composition of the feedstock is, and how it differs from conventional oil. Additional research into best management practices, spill prevention practices, and cleanup and response planning is needed before permitting a major increase in the amount of refinery-bound tanker traffic coming into California's waters.

We ask that the final EIR contain and make publicly available an independent scientific study on the risks to – and best achievable protection of – state waters from spills of feedstocks. This study should evaluate the hazards and potential hazards associated with a spill or leak of feedstocks. The study should encompass potential spill impacts to natural resources, the public, occupational health and safety, and environmental health and safety. This analysis should include calculations of the economic and ecological impacts of a worst-case spill event in the San Francisco Bay ecosystem, along the California coast, and along the entire projected shipping route for the expanded marine terminal.

Based on this study, the final EIR should also include a full review of the spill response capabilities and criteria for oil spill contingency plans and oil spill response organizations (OSROs) responsible for remediating spills. We respectfully request that the final EIR include

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[288] *See* Senator Bill Dodd, Letter Re: Vallejo Odor and Bay Area Air Quality Management District Response (March 8, 2017), *available at* https://www.documentcloud.org/documents/3514729-Sen-Dodd-BAAQMD-Letter-3-8-17.html.

an analysis indicating whether there are OSROs currently operating in California capable of responding adequately to a spill of the contemplated feedstocks. Further, the adequacy of an OSRO's spill response capability should be compared to the baseline of no action rather than to a best available control technology standard.

While California's regulatory agencies have recently been granted cleanup authority over spills of biologically-derived fuel products, no such authority or responsibility has been granted for feedstocks. If there are no current plans for OSROs to respond to spills of feedstocks in California waters, the final EIR must evaluate the impacts of such a spill under inadequate cleanup scenarios. The DEIR fails to adequately evaluate how spills of feedstocks will be remediated, if at all.

Additional ships delivering oil to the Project would be passing through a channel that the Army Corps of Engineers has slated for reduced dredging. The Project thus contemplates increasing ship traffic through a channel that could be insufficiently dredged. The final EIR must evaluate the safety risks posed by reduced Pinole Shoal Navigation Channel Maintenance Dredging.[289] Should Phillips 66 be required to dredge the channel, it must fully evaluate and disclose impacts from such dredging in its environmental analysis.

Finally, the final EIR must evaluate ship maintenance impacts. Increased shipping means increased maintenance in regional shipyards and at regional anchorages, and these impacts must be analyzed.

B. The DEIR Wrongly Concludes There Would be No Aesthetic Impacts

The DEIR claims that there would be no aesthetic impacts, and fails to analyze the significant increase in ship traffic. DIER xxix (Table ES-3). San Francisco Bay is considered a world class scenic vista, with billions of dollars of tourism dependent on a setting of natural beauty. The DEIR even acknowledges that "[b]ackground views of the bay provide a scenic quality." DEIR 4.2-12. Yet minimal analysis has been done of what impact such a drastic increase in ship traffic would do to San Francisco Bay's aesthetics, including a significant new source of light or glare (ships).

> Marine traffic in San Pablo Bay is part of the existing visual character. The San Pablo Bay has other industrial shipping facilities and marine terminals in proximity to the Rodeo Site that contribute to vessel traffic in the Bay. The proposed increase in marine traffic may result in a slight degradation of the natural views of the Bay and from the Bay of the surrounding natural landscape and hillsides. However, given the existing industrial visual character of the Rodeo Refinery and current Marine

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[289] Memorandum for Commander, South Pacific Division (CWSPD-PD), FY 17 O&M Dredging of San Francisco (SF) Bay Navigation Channels, U.S. Army Corps of Engineers (Jan. 12, 2017) (Army Corps memo discussing deferred dredging).

> Terminal activity, the increase in marine traffic would not be highly noticeable. Impacts on scenic views would be less than significant. No mitigation is required.

DEIR 4.2-27. Tripling ship traffic and then stating it does not constitute an impact because the area is already degraded by the same sorts of impacts is false, cynical, and ignores environmental justice concerns. The final EIR must take a hard look at these impacts, as well as impacts along expected transportation corridors and impacts from an increase in spill risk.

C. Air Quality Impacts Must Be Evaluated for an Adequate Study Area

Air quality impacts evaluated by the DEIR must include an adequate study area in order to appropriately estimate the Project's potential to result in substantial increases in criteria pollutant emissions. An increase to 361 ships per year carries with it obvious air quality impacts from ship exhaust. DEIR 4.3-70 ("marine traffic annual mass emissions are expected to increase during the Project due to increased vessel traffic"). These impacts must be evaluated by location, as is done for rail impacts (*see* DEIR 4.3-72, "Rail Transport Outside the SFBAAB (Significant and Unavoidable, Mitigation Pre-Empted)"), for every mile the ships travel, and for every community along their route, not just between the refinery and various anchorage points. The DEIR fails to do so, and also fails to evaluate health impacts from these routes and at various locations. Ships will not arrive at the Project terminal from out of a vacuum, and each additional ship beyond those currently in fact using the terminal – not just those currently permitted – must be evaluated.

Phillips 66 does not have a good record of avoiding air quality violations at its Rodeo refinery. Within the last couple of years, BAAQMD settled for nearly $800,000 with Phillips 66 for 87 air quality violations between 2010 and 2014.[290] Such past violations must be evaluated when considering the likelihood of future violations that may relate to a change in feed stock or increased refinery activity as a result of the marine terminal expansion.

Provision of shore power should also be considered as a mitigation measure.

D. Recreational Impacts Are Potentially Significant

The DEIR states that there is no possibility of impact to recreation and that it has been eliminated from detailed analysis. DEIR 4-6 (4.1.5 Recreation). This is error. San Francisco Bay is a massive recreational area, and the increase in maritime traffic has a direct impact on opportunities for recreation on the Bay. Increased ship traffic qualifies as substantial physical deterioration of an existing facility. In addition, spills of feedstocks or finished products either from ships moving to and from the refinery or from the refinery itself have the potential to impact existing recreational sites. The DEIR contemplates a huge increase in the amount of product carried by ship across the Pacific Ocean and through San Francisco Bay, and each additional trip carries with it an increased chance of a spill. The final EIR must evaluate

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[290] "Air District settles case with Phillips 66," BAAQMD Press Release (August 3, 2016), *available at* http://www.baaqmd.gov/~/media/files/communications-and-outreach/publications/news-releases/2016/settle_160803_phillips-pdf.pdf?la=en.

recreational impacts from increased ship traffic and spill risk, both in San Francisco Bay and at every point along contemplated transportation corridors.

E. The Project Implicates Potential Utilities and Service System Impacts

The DEIR states that there is no possibility of impacts to utilities and service systems and that it has been eliminated from detailed analysis. DEIR 4-7 (4.1.6 Utilities and Service Systems). This is error. The increase in maritime traffic has a direct impact on ship maintenance, anchorages, and upkeep on the Bay. Increased ship traffic would accelerate deterioration of existing facilities. In addition, spills of feedstocks or finished products either from ships moving to and from the refinery or from the refinery itself have the potential to impact existing ship facilities. The DEIR contemplates a huge increase in the amount of product carried by ship across the Pacific Ocean and through San Francisco Bay, and each additional trip carries with it an increased chance of a spill. The final EIR must evaluate utility and service system impacts from increased ship traffic and spill risk, both in San Francisco Bay and at every point along contemplated transportation corridors.

F. Biological Impacts and Impacts to Wildlife are Potentially Significant and Inadequately Mitigated

The DEIR makes clear that there are numerous special status marine and aquatic species present, yet does not sufficiently protect these species. For each of the following impact areas, we request that adequate mitigation be evaluated and applied for each species type.

Increased shipping as a result of biofuel production and transport causes stress to the marine environment and can thus impact wildlife. Wake generation, sediment re-suspension, noise pollution, animal-ship collisions (or ship strikes), and the introduction of non-indigenous species must all be studied as a part of the EIR process. "Wake generation by large commercial vessels has been associated with decreased species richness and abundance (Ronnberg 1975) given that wave forces can dislodge species, increase sediment re-suspension (Gabel et al. 2008), and impair foraging (Gabel et al. 2011)."[291] Wake generation must be evaluated as an environmental impact of the Project.

The DEIR contains ample data supporting vessel speed reduction as a means to avoid adverse impacts from ship strikes. *See, e.g.*, DEIR 4.4-128. Yet vessel speed reductions are not mandatory, and there is no requirement that the increased vessel traffic contemplated by the Project would adhere to speed recommendations to protect wildlife. The mitigation measures proposed by the DEIR amount to nothing more than sending some flyers. The final EIR should contemplate additional mitigation that includes tracking actual vessel speeds and mitigation for vessels that exceed 10 knots, as well as incentives for vessels to adhere to recommended speeds such as monetary bonuses or fines. Mitigation Measures BIO-1(a) and (b) are insufficient because they do not contemplate effective measures to ensure safe vessel speeds and to mitigate for exceedances.

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[291] Green *et al*. 2017.

Acoustic impacts can also be extremely disruptive. As the DEIR points out, "broadly elevated underwater noise and concentration may occur in areas with major ports and harbors (Erbe et al. 2012; Redfern et al. 2017)." DEIR 4.4-130. "Increased tanker traffic threatens marine fish, invertebrate, and mammal populations by disrupting acoustic signaling used for a variety of processes, including foraging and habitat selection (e.g. Vasconcelos et al. 2007; Rolland et al. 2012), and by physical collision with ships – a large source of mortality for marine animals near the surface along shipping routes (Weir and Pierce 2013)."[292] Acoustic impacts must be evaluated as an environmental impact of the Project. However, in spite of the DEIR's admission that porpoises have a threshold for injury of 173 dB, and that median vessel sound levels would be 177.9-178.1 dB, it still finds only minimal disturbance and concludes that "No noise-related injuries would be expected." DEIR 4.4-132 – 4.4-133. This discrepancy must be explained in the final EIR, and mitigation measures, such as reducing vessel speed and the other potential mitigations listed in the DEIR (though not implemented, *see* DEIR 4.4-134) must be implemented and incentivized. In addition, the DEIR must require that acoustic safeguards comport with recent scientific guidance for evaluating the risk to marine species.[293]

Oil spill impacts are not adequately evaluated for biological resources and wildlife in the DEIR. The DEIR erroneously assumes that spills feedstocks for biofuels can be treated the same as petroleum-based spills. *See, e.g.*, DEIR 4.4-139. There is no evidence that this is the case presented in the DEIR, and there is no evidence that current spill response capabilities are capable of or even authorized to respond to spills of non-petroleum feedstocks. The DEIR's proposed mitigation measures are insufficient to address these concerns.

Invasive species are also a dangerous side effect of commercial shipping. "Tankers also serve as a vector for the introduction of non-indigenous species (NIS) via inadvertent transfer of propagules from one port to another (Drake and Lodge 2004), with the probability of introduction depending on the magnitude and origin of shipping traffic along tanker routes (Table 1 and Figure 3; Lawrence and Cordell 2010)." Invasive species impacts must be evaluated as an environmental impact of the Project. Yet the DEIR's mitigation measures are insufficient. Again, sending a flyer does not prevent the problems identified in the DEIR. DEIR 4.4-142. Additional recommended mitigation measures include incentives for ballast water remediation that ensures protection of sensitive areas and requiring documentation of ballast water exchanges from all visiting ships.

In addition, the GHG emissions from the Project will contribute to climate change and in turn harm marine species. The combined GHG emissions from the facility, increased vessel traffic, and upstream and downstream emissions will have adverse impacts on marine species through temperature changes and ocean acidification. These changes may trigger changes to population distributions or migration, making ship strikes in some areas more likely.[294]

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[292] *Id.*

[293] See Southall et al., Marine Mammal Noise Exposure Criteria: Assessing the Severity of Marine Mammal Behavioral Responses to Human Noise, *Aquatic Mammals*, (2021) 47(5), 421-464.

[294] See Redfern et al., Effects of Variability in Ship Traffic and Whale Distributions on the Risk of Ships Striking Whales, *Frontiers in Marine Science* (Feb. 2020) Vol. 6, art. 793.

G. Noise and Vibration Impact Analysis is Insufficient

According to the DEIR, "[t]he Project would not result in an increased number of vessels calling at the Marine Terminal on a peak day. Accordingly, noise levels would not increase as a result of peak-day vessel activity." DEIR 4.12-396. This analysis is insufficient. The DEIR admits that overall vessel trips will drastically increase, but no analysis is made of what noise impacts will result from the increased number of vessels. The final EIR must evaluate noise impacts associated with the increase in vessel trips.

H. Transportation and Traffic Impacts Analysis is Inadequate

Additional impacts must be analyzed starting at the port that ships associated with the Project take on their cargos and ending at the ports they discharge it to. The EIR should include shipping impacts to public or non-Project commercial vessels and businesses, including impacts to recreational boaters and ferries, that might experience increased delay, anchorage waits or related crowding, and increased navigational complexity. Collision and spill analysis should not be limited to just the vessels calling at the marine terminal associated with the Project: increased ship traffic could result in accidents among other ships or waterborne vessels. This likelihood must be analyzed in the final EIR, just as vehicular traffic increases are analyzed for their impact on overall accident rates and traffic, generally. Such shipping traffic impact evaluations should extend to spills, air quality, marine life impacts from ship collisions, and other environmental impacts evaluated by the DEIR that could impact shipping traffic.

I. Tribal Cultural Resources Impacts Analysis is Inadequate

The only tribal cultural impacts examined by the DEIR are construction impacts. But many of the people who historically called this area home had an intimate relationship with the Bay and the water, so impacts from increased marine terminal use and increased shipping traffic, as well as associated increased spill risk and impacts to fish and wildlife, must be examined in the final EIR as well. Examples of tribes that should be consulted include the Me-Wuk (Coast Miwok), the Karkin, the Me-Wuk (Bay Miwok), the Confederated Villages of Lisjan, Graton Rancheria, the Muwekma, the Ramaytush, and the Ohlone.

J. The Project Risks Significant Environmental Justice and Economic Impacts

To the extent the Project utilizes offsets or credits, these have an undue impact on disadvantaged and already polluted communities, and the environmental justice impacts of such use must be evaluated. Violations, such as the air quality violations referenced above, also have an undue impact on disadvantaged and already polluted communities, impacts that cannot be addressed through monetary penalties.

Rodeo ranks in the top 8% of the state's highest concentration of hazardous waste facilities, has a high concentration of contamination from Toxic Release Inventory chemicals, ranking in the top 3% for that factor.[295] Moreover, Rodeo also suffers from a high rate of low birth weights and asthma, ranking in the top 1% and 16%, respectively.[296]

Fisheries would also be a major casualty of any large spill, and struggling fishing communities would be hardest hit by such impacts. Dungeness crab landings, for instance, were 3.1 million pounds in 2015, down almost 83% from the year before, with Oregon landings down a similar percentage.[297] Additional stress on these fisheries as a result of a spill or from other impacts from increased tanker traffic could have catastrophic consequences that need to be examined in the final EIR. Overall, California produced 366 million pounds of fish worth 252.6 million dollars in 2014 and 195 million pounds of fish worth 143.1 million dollars in 2015, and threats to this industry that result from the Project must be evaluated in the EIR.

K. The DEIR Fails to Disclose and Analyze Significant Additional Impacts

1. Public Trust Resources

The marine terminal that the Project targets for drastically increased ship traffic occupies 16.7 acres of leased land, filled and unfilled. This land is California-owned sovereign land in San Pablo Bay, and as a result the California State Lands Commission is a responsible party. Public trust impacts to this land and to other public trust resources must be evaluated in the final EIR.

2. Cross-Border Impacts

Shipping and ship traffic impacts extend across state and national borders. The final EIR must take into account environmental impacts that occur outside of California as a result of actions within California.

3. Terrorism Impacts

More ships bring increased risk. Anti-terrorism and security measures, as well as the potential impacts from a terrorist or other non-accidental action, must be evaluated in the final EIR.

XII. CONCLUSION

We request that the County address and correct the errors and deficiencies in the DEIR explained in this Comment. Given the extensive additional information that needs to be provided in an EIR to satisfy the requirements of CEQA, we request that the new information be included in a recirculated DEIR to ensure that members of the public have full opportunity to comment on it.

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[295] OEHHA, Cal Enviro Screen 1.1 (amended), Statewide Zip Code Results, Rodeo, *available at* http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56.

[296] *Id.*

[297] *See* 2015 NOAA Fisheries of the United States.

Thank you for your consideration of these Comments.

Very truly yours,

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APPENDIX A

Karras, G., *Changing Hydrocarbons Midstream* (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

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August 2021

ABSTRACT

Moves to deoxygenate farmed lipids with hydrogen by repurposing troubled crude refining assets for "drop in" biofuels add a new carbon source to the liquid hydrocarbon fuel chain, with the largest biorefineries of this type that the world has ever seen now proposed in California. Characteristics of this particular biofuel technology were assessed across its shared fuel chain with petroleum for path-dependent feedstock acquisition, processing, fuel mix, and energy system effects on the environment at this newly proposed scale. The analysis was grounded by site-specific data in California.

This work found significant potential impacts are foreseeable. Overcommitment to purpose-grown biomass imports could shift emissions out of state instead of sequestering carbon. Fossil fuel assets repurposed for hydrogen-intensive deoxygenation could make this type of biorefining more carbon intensive than crude refining, and could worsen refinery fire, explosion, and flaring hazards. Locked into making distillate fuels, this technology would lock in diesel and compete with zero-emission freight and shipping for market share and hydrogen. That path-dependent impact could amplify, as electric cars replace gasoline and idled crude refining assets repurpose for more biomass carbon, to turn the path of energy transition away from climate stabilization. Crucially, this work also found that a structural disruption in the liquid hydrocarbon fuel chain opened a window for another path, to replace the freight and shipping energy function of crude refining without risking these impacts. The type and use of hydrogen production chosen will be pivotal in this choice among paths to different futures.

ACRONYMS AND TERMS

Barrel (b):	A barrel of oil is a volume of 42 U.S. gallons.
BEV:	Battery-electric vehicle.
Biofuel:	Hydrocarbons derived from biomass and burned for energy.
Biomass:	Any organic material that is available on a recurring basis, excluding fossil fuels.
Carbon intensity:	The amount of climate emission caused by a given amount of activity at a particular emission source. Herein, CO_2 or CO_2e mass per barrel refined, or SCF hydrogen produced.
Carbon lock-in:	Resistance to change of carbon-emitting systems that is caused by mutually reinforcing technological, capital, institutional, and social commitments to the polluting system which have become entrenched as it was developed and used. A type of path dependance.
Catalyst:	A substance that facilitates a chemical reaction without being consumed in the reaction.
Ester:	A molecule or functional group derived by condensation of an alcohol and an acid with simultaneous loss of water. Oxygen, carbon, and other elements are bonded together in esters.
Electrolysis:	Chemical decomposition produced by passing an electric current through a liquid or solution containing ions. Electrolysis of water produces hydrogen and oxygen.
FCEV:	Fuel cell electric vehicle.
HDO:	Hydrodeoxygenation. Reactions that occur in HEFA processing.
HEFA:	Hydrotreating esters and fatty acids. A biofuel production technology.
Hydrocarbon:	A compound of hydrogen and carbon.
Lipids:	Organic compounds that are oily to the touch and insoluble in water, such as fatty acids, oils, waxes, sterols, and triacylglycerols (TAGS). Fatty acids derived from TAGs are the lipid-rich feedstock for HEFA biofuel production.
MPC:	Marathon Petroleum Corporation, headquartered in Findlay, OH.
P66:	Phillips 66 Company, headquartered in Houston, TX.
SCF:	Standard cubic foot. 1 ft^3 of gas that is not compressed or chilled.
TAG:	Triacylglycerol. Also commonly known as triglyceride.
Ton (t):	Metric ton.
ZEV:	Zero-emission vehicle.

CONTENTS

Supporting Material — Separately Bound Appendix[1]

FINDINGS AND TAKEAWAYS

Finding 1. Oil companies are moving to repurpose stranded and troubled petroleum assets using technology called "Hydrotreated Esters and Fatty Acids" (HEFA), which converts vegetable oil and animal fat lipids into biofuels that refiners would sell for combustion in diesel engines and jet turbines. The largest HEFA refineries to be proposed or built worldwide to date are now proposed in California.

Takeaways

F1.1 Prioritizing industry asset protection interests ahead of public interests could lock in HEFA biofuels instead of cleaner alternatives to petroleum diesel and jet fuel.

F1.2 HEFA refining could continue to expand as refiners repurpose additional crude refining assets that more efficient electric cars will idle by replacing gasoline.

F1.3 Assessment of potential impacts across the HEFA fuel chain is warranted before locking this new source of carbon into a combustion-based transportation system.

Finding 2. Repurposing refining assets for HEFA biofuels could increase refinery explosion and fire hazards. Switching from near-zero oxygen crude to 11 percent oxygen biomass feeds would create new damage mechanisms and intensify hydrogen-driven exothermic reaction hazards that lead to runaway reactions in biorefinery hydro-conversion reactors. These hydrogen-related hazards cause frequent safety incidents and even when safeguards are applied, recurrent catastrophic explosions and fires, during petroleum refining. At least 100 significant flaring incidents traced to these hazards occurred since 2010 among the two refineries where the largest crude-to-biofuel conversions are now proposed. Catastrophic consequences of the new biorefining hazards are foreseeable.

Takeaways

F2.1 Before considering public approvals of HEFA projects, adequate reviews will need to report site-specific process hazard data, including pre-project and post-project equipment design and operating data specifications and parameters, process hazard analysis, hazards, potential safeguards, and inherent safety measures for each hazard identified.

F2.2 County and state officials responsible for industrial process safety management and hazard prevention will need to ensure that safety and hazard prevention requirements applied to petroleum refineries apply to converted HEFA refineries.

Finding 3. Flaring by the repurposed biorefineries would result in acute exposures to episodic air pollution in nearby communities. The frequency of these recurrent acute exposures could increase due to the new and intensified process safety hazards inherent in deoxygenating the new biomass feeds. Site-specific data suggest bimonthly acute exposure recurrence rates for flare incidents that exceed established environmental significance thresholds. This flaring would result in prolonged and worsened environmental justice impacts in disparately exposed local communities that are disproportionately Black, Brown, or low-income compared with the average statewide demographics.

Takeaways

F3.1 Before considering public approvals of HEFA projects, adequate reviews will require complete analyses of potential community-level episodic air pollution exposures and prevention measures. Complete analyses must include worst-case exposure frequency and magnitude with impact demographics, apply results of process hazard, safeguard, and inherent safety measures analysis (F2.1), and identify measures to prevent and eliminate flare incident exposures.

F3.2 The Bay Area, San Joaquin Valley, and South Coast air quality management districts will need to ensure that flare emission monitoring and flaring prevention requirements applied to petroleum refineries apply to converted HEFA refineries.

Finding 4. Rather than contributing to a reduction in emissions globally, HEFA biofuels expansion in California could actually shift emissions to other states and nations by reducing the availability of limited HEFA biofuels feedstock elsewhere. Proposed HEFA refining for biofuels in California would exceed the per capita state share of total U.S. farm yield for all uses of lipids now tapped for biofuels by 260 percent in 2025. Foreseeable further HEFA growth here could exceed that share by as much as 660 percent in 2050. These impacts are uniquely likely and pronounced for the type of biomass HEFA technology demands.

Takeaways

F4.1 A cap on in-state use of lipids-derived biofuel feedstocks will be necessary to safeguard against these volume-driven impacts. *See also Takeaway F6.1.*

F4.2 Before considering public approvals of HEFA projects, adequate reviews will need to fully assess biomass feedstock extraction risks to food security, low-income families, future global farm yields, forests and other natural carbon sinks, biodiversity, human health, and human rights using a holistic and precautionary approach to serious and irreversible risks.

F4.3 This volume-driven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively via separate policy or investment actions.

Changing Hydrocarbons Midstream

Finding 5. Converting crude refineries to HEFA refineries would increase the carbon intensity of hydrocarbon fuels processing to 180–240 percent of the average crude refinery carbon intensity nationwide. Refiners would cause this impact by repurposing otherwise stranded assets that demand more hydrogen to deoxygenate the type of biomass the existing equipment can process, and supply that hydrogen by emitting some ten tons of carbon dioxide per ton of hydrogen produced. In a plausible HEFA growth scenario, cumulative CO_2 emissions from continued use of existing California refinery hydrogen plants alone could reach 300–400 million metric tons through 2050.

Takeaways

F5.1 Before considering public approvals of HEFA projects, adequate reviews will need to complete comprehensive biorefinery potential to emit estimates based on site-specific data, including project design specifications, engineering for renewable-powered electrolysis hydrogen capacity at the site, and potential to emit estimates with and without that alternative. *See also Takeaways F7.1–4.*

Finding 6. HEFA biofuels expansion that could be driven by refiner incentives to repurpose otherwise stranded assets is likely to interfere with state climate protection efforts, in the absence of new policy intervention. Proposed HEFA plans would exceed the lipids biofuel caps assumed in state climate pathways through 2045 by 2025. Foreseeable further HEFA biofuels expansion could exceed the maximum liquid hydrocarbon fuels volume that can be burned in state climate pathways, and exceed the state climate target for emissions in 2050.

Takeaways

F6.1 A cap on lipids-derived biofuels will be necessary to safeguard against these HEFA fuel volume-driven impacts. *See also Takeaway F4.1.*

F6.2 Oil company incentives to protect refining and liquid fuel distribution assets suggest HEFA biofuels may become locked-in, rather than transitional, fuels.

F6.3 A cap on HEFA biofuels would be consistent with the analysis and assumptions in state climate pathways.

Finding 7. A clean hydrogen alternative could prevent emissions, spur the growth of zero-emission fuel cell vehicle alternatives to biofuels, and ease transition impacts.

Early deployment of renewable-powered electrolysis hydrogen production at California crude refineries during planned maintenance or HEFA repurposing could prevent 300–400 million metric tons of CO_2 emissions through 2050 and support critically needed early deployment of energy integration measures for achieving zero emission electricity and heavy-duty vehicle fleets.

Moreover, since zero-emission hydrogen production would continue on site for these zero-emission energy needs, this measure would lessen local transition impacts on workers and communities when refineries decommission.

Takeaways

F7.1 This feasible measure would convert 99 percent of current statewide hydrogen production from carbon-intensive steam reforming to zero-emission electrolysis. This clean hydrogen, when used for renewable grid balancing and fuel cell electric vehicles, would reap efficiency savings across the energy system.

F7.2 Early deployment of the alternatives this measure could support is crucial during the window of opportunity to break free from carbon lock-in which opened with the beginning of petroleum asset stranding in California last year and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels.

F7.3 During the crucial early deployment period, when fuel cell trucks and renewable energy storage could be locked out from use of this zero-emission hydrogen by excessive HEFA growth, coupling this electrolysis measure with a HEFA biofuel cap (*F4.1; F6.1*) would greatly increase its effectiveness.

F7.4 Coupling the electrolysis and HEFA cap measures also reduces HEFA refinery hazard, localized episodic air pollution and environmental justice impacts.

F7.5 The hydrogen roadmap in state climate pathways includes converting refineries to renewable hydrogen, and this measure would accelerate the deployment timeline for converting refinery steam reforming to electrolysis hydrogen production.

INTRODUCTION

i.1 Biofuels in energy systems

Fossil fuels redefined the human energy system. Before electric lights, before gaslights, whale oil fueled our lanterns. Long before whaling, burning wood for light and heat had been standard practice for millennia. Early humans would learn which woods burned longer, which burned smokier, which were best for light, and which for heat. Since the first fires, we have collectively decided on which biofuel carbon to burn, and how much of it to use, for energy.

We are, once again, at such a collective decision point. Biofuels—hydrocarbons derived from biomass and burned for energy—seem, on the surface, an attractive alternative to crude oil. However, there are different types of biofuels and ways to derive them, each carrying with it different environmental impacts and implications. Burning the right type of biofuel for the right use *instead* of fossil fuels, such as cellulose residue-derived instead of petroleum-derived diesel for old trucks until new zero emission hydrogen-fueled trucks replace them, might help to avoid severe climate and energy transition impacts. However, using more biofuel burns more carbon. Burning the wrong biofuel *along with* fossil fuels can increase emissions—and further entrench combustion fuel infrastructure that otherwise would be replaced with cleaner alternatives.

i.1.1 Some different types of biofuel technologies

Corn ethanol

Starch milled from corn is fermented to produce an alcohol that is blended into gasoline. Ethanol is about 10% of the reformulated gasoline sold and burned in California.

Fischer-Tropsch synthesis

This technology condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce synthetic biogas, gasoline, jet fuel, or diesel biofuels. A wide range of materials can be gasified for this technology. Fischer-Tropsch synthesis can make any or all of these biofuels from cellulosic biomass such as cornstalk or sawmill residues.

Biofuel in the Climate System 101

People and other animals exhale carbon dioxide into the air while plants take carbon dioxide out of the air. Biofuel piggybacks on—and alters—this natural carbon cycle. It is fuel made to be burned but made from plants or animals that ate plants. Biofuels promise to let us keep burning fuels for energy by putting the carbon that emits back into the plants we will make into the fuels we will burn next year. All we have to do is grow a lot of extra plants, and keep growing them.

But can the biofuel industry keep that promise?

This much is clear: burning biofuels emits carbon and other harmful pollutants from the refinery stack and the tailpipe. Less clear is how many extra plants we can grow; how much land for food, natural ecosystems and the carbon sinks they provide it could take; and ultimately, how much fuel combustion emissions the Earth can take back out of the air.

Some types of biofuels emit more carbon than the petroleum fuels they replace, raise food prices, displace indigenous peoples, and worsen deforestation. Other types of biofuels might help, along with more efficient and cleaner renewable energy and energy conservation, to solve our climate crisis.

How much of which types of biofuels we choose matters.

"Biodiesel"

Oxygen-laden hydrocarbons made from lipids that can only be burned along with petroleum diesel is called "biodiesel" to denote that limitation, which does not apply to all diesel biofuels.

Hydrotreating esters and fatty acids (HEFA)

HEFA technology produces hydrocarbon fuels from lipids. This is the technology crude refiners propose to use for biofuels. The diesel hydrocarbons it produces are different from "biodiesel" and are made differently, as summarized directly below.

i.2 What is HEFA technology?

i.2.1 <u>How HEFA works</u>

HEFA removes oxygen from lipidic (oily) biomass and reformulates the hydrocarbons this produces so that they will burn like certain petroleum fuels. Some of the steps in HEFA refining are similar to those in traditional petroleum refining, but the "deoxygenation" step is very different, and that is because lipids biomass is different from crude and its derivatives.

i.2.2 <u>HEFA feedstocks</u>

Feedstocks are detailed in Chapter 2. Generally, all types of biomass feedstocks that HEFA technology can use contain lipids, which contain oxygen, and nearly all of them used for HEFA biofuel today come directly or indirectly from one (or two) types of farming.

Purpose-grown crops

Vegetable oils from oil crops, such as soybeans, canola, corn, oil palm, and others, are used directly and indirectly as HEFA feedstock. Direct use of crop oils, especially soy, is the major portion of total HEFA feeds. Indirect uses are explained below. Importantly, these crops were cultivated for food and other purposes which HEFA biofuels now compete with—and a new oil crop that has no existing use can still compete for farmland to grow it. Some other biofuels, such as those which can use cellulosic residues as feedstock for example, do not raise the same issue. Thus, in biofuels jargon, the term "purpose-grown crops" denotes this difference among biofuels.

Animal fats

Rendered livestock fats such as beef tallow, pork lard, and chicken fat are the second largest portion of the lipids in HEFA feedstock, although that might change in the future if refiners tap fish oils in much larger amounts. These existing lipid sources also have existing uses for food and other needs, many of which are interchangeable among the vegetable and animal lipids. Also, particularly in the U.S. and similar agricultural economies, the use of soy, corn and other crops as livestock feeds make purpose-grown crops the original source of these HEFA feeds.

Used cooking oils

Used cooking oil (UCO), also called yellow grease or "waste" oil, is a variable mixture of used plant oils and animal fats, typically collected from restaurants and industrial kitchens. It notably could include palm oil imported and cooked by those industries. HEFA feeds include UCO, though its supply is much smaller than those of crop oils or livestock fats. UCO, however, originates from the same purpose grown oil crops and livestock, and UCO has other uses, many of which are interchangeable with the other lipids, so it is not truly a "waste" oil.

i.2.3 HEFA processing chemistry

The HEFA process reacts lipids biomass feedstock with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. The intended reactions of this "hydro-conversion" accomplish the deoxygenation and reformulation steps noted above.

The role of hydrogen in HEFA production

Hydrogen is consumed in several HEFA process reactions, especially deoxygenation, which removes oxygen from the HEFA process hydrocarbons by bonding with hydrogen to form water. Hydrogen also is essential for HEFA process reaction control. As a result, HEFA processing requires vast amounts of hydrogen, which HEFA refineries must produce in vast amounts. HEFA hydro-conversion and hydrogen reaction chemistry are detailed in Chapter 1.

i.2.4 What HEFA produces

"Drop in" diesel

One major end product of HEFA processing is a "drop-in" diesel that can be directly substituted for petroleum diesel as some, or all, of the diesel blend fueled and burned. Drop-in diesel is distinct from biodiesel, which must be blended with petroleum diesel to function in combustion engines and generally needs to be stored and transported separately. Drop-in diesel is also referred to as "renewable" diesel, however, those labels also apply to diesel made by other biofuel technologies, so diesel produced by the HEFA process is called "HEFA diesel" herein.

"Sustainable Aviation Fuel"

The other major end product of HEFA processing is a partial substitute for petroleum-based jet fuel, sometimes referred to as "Sustainable Aviation Fuel" or "SAF," which also is produced by other biofuel technologies. HEFA jet fuel is allowed by aviation standards to be up to a maximum of 50% of the jet fuel burned, so it must be blended with petroleum jet fuel.

i.3 Conversions of Crude oil refineries to HEFA

i.3.1 Current and proposed conversions of oil refineries

Phillips 66 Co. (P66) proposes to convert its petroleum refinery in Rodeo, CA into a 80,000 barrel per day (b/d) biorefinery.[2] In nearby Martinez, Marathon Petroleum Corporation (MPC) proposes a 48,000 b/d biorefinery[3] at the site where it closed a crude refinery in April 2020.[4] Other crude-to-biofuel refinery conversions are proposed or being built in Paramount, CA (21,500 b/d new capacity),[5] Bakersfield, CA (15,000 b/d),[6] Port Arthur, TX (30,700 b/d),[7] Norco, LA (17,900 b/d new capacity),[8] and elsewhere. All of these projects are super-sized compared with the 2,000–6,000 b/d projects studied as of just a few years ago.[9] The P66 Rodeo and MPC Martinez projects are the largest of their kind to be proposed or built to date. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10]

i.3.2 Repurposing of existing equipment

Remarkably, all of the crude-to-biofuel conversion projects listed above seek to use HEFA technology—none of the refiners chose Fischer-Tropsch synthesis despite its greater flexibility than HEFA technology and ability to avoid purpose-grown biomass feedstock. However, this is consistent with repurposing the plants already built. The California refiners propose to repurpose existing hydro-conversion reactors—hydrocrackers or hydrotreaters—for HEFA processing, and existing hydrogen plants to supply HEFA process hydrogen needs.[2–6] Moreover, it is consistent with protecting otherwise stranded assets; repurposed P66 and MPC assets have recently been shut down, are being shut down, or will potentially be unusable soon, as described in Chapter 1.

While understandable, this reaction to present and impending petroleum asset stranding appears to be driving our energy system toward HEFA technology instead of potentially cleaner alternatives at an enormous scale, totaling 164,500 b/d by 2024 as proposed now in California. This assets protection reaction also presents a clear potential for further HEFA expansion. Refiners could continue to repurpose petroleum refining assets which will be idled as by the replacement of gasoline with more efficient electric passenger vehicles.

Before allowing this new source of carbon to become locked into a future combustion-based transportation system, assessment of potential impacts across the HEFA fuel chain is warranted.

i.4 Key questions and concerns about crude-to-biofuel conversions

i.4.1 Potential impacts of biomass feedstock acquisition

Proposed and potential HEFA expansions in California would rapidly and substantially increase total demand for globally traded agricultural lipids production. This could worsen food insecurity, risk deforestation, biodiversity and natural carbon sink impacts from expansions of farm and pasture lands, and drive populations elsewhere to prioritize use of their remaining lipids shares for food. Biofuel, biodiversity, and climate analysts often refer to the food security impact and agriculture expansion risks in terms of food price and "indirect land use" impacts. The latter effect, on *where* a globally limited biofuel resource could be used, is often referred to by climate policy analysts as an emission-shifting or "leakage" impact. Chapter 2 reviews these potential feedstock acquisition impacts and risks.

i.4.2 Potential impacts of HEFA refinery processing

Processing a different oil feedstock is known to affect refinery hazards and emissions, and converted HEFA refineries would process a very different type of oil feedstock. The carbon intensity—emissions per barrel processed—of refining could increase because processing high-oxygen plant oils and animal fats would consume more hydrogen, and the steam reformers that refiners plan to repurpose emit some ten tons of CO_2 per ton of hydrogen produced. Explosion and fire risks could increase because byproducts of refining the new feeds pose new equipment damage hazards, and the extra hydrogen reacted with HEFA feeds would increase the frequency and magnitude of dangerous runaway reactions in high-pressure HEFA reactors. Episodic air pollution incidents could recur more frequently because refiners would partially mitigate the impacts of those hazards by rapid depressurization of HEFA reactor contents to refinery flares, resulting in acute air pollutant exposures locally. Chapter 3 assesses these potential impacts.

i.4.3 Potential impacts on climate protection pathways

A climate pathway is a road map for an array of decarbonization technologies and measures to be deployed over time. California has developed a range of potential pathways to achieve its climate goals—all of which rely on replacing most uses of petroleum with zero-emission battery-electric vehicles and fuel cell-electric vehicles (FCEVs) energized by renewable electricity. Proposed and potential HEFA biofuels growth could exceed this range of state pathways or interfere with them in several ways that raise serious questions for our future climate.

HEFA biofuels could further expand as refiners repurpose assets idled by the replacement of gasoline with electric vehicles. This could exceed HEFA caps *and* total liquid fuels volumes in the state climate pathways. Hydrogen committed to HEFA growth would not be available for FCEVs and grid-balancing energy storage, potentially slowing zero-emission fuels growth. High-carbon hydrogen repurposed for HEFA refining, which could not pivot to zero-emission FCEV fueling or energy storage, could lock in HEFA biofuels instead of supporting transitions to cleaner fuels. These critical-path climate factors are assessed in Chapter 4.

i.4.4 Alternatives, opportunities and choices

Zero emission hydrogen alternative

Renewable-powered electrolysis of water produces zero-emission hydrogen that could replace existing high-carbon hydrogen production during refinery maintenance shutdowns and HEFA conversions. Indeed, a "Hydrogen Roadmap" in state climate pathways envisions converting all refineries to renewable hydrogen. This measure could cut emissions, support the growth of FCEVs and grid-balancing energy needed to further expand renewable electricity and zero-emission fuels, and reduce local transition impacts when refineries decommission.

Window of opportunity

A crucial window of opportunity to break out of carbon lock-in has opened with the beginning of California petroleum asset stranding in 2020 and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels. The opening of this time-sensitive window underscores the urgency of early deployment for FCEV, energy storage, and zero-emission fuels which renewable-powered electrolysis could support.

Potential synergies with HEFA biofuels cap

Coupling this measure with a HEFA biofuels cap has the potential to enhance its benefits for FCEV and cleaner fuels deployment by limiting the potential for electrolysis hydrogen to instead be committed to HEFA refining during the crucial early deployment period, and has the potential to reduce HEFA refining hazard, episodic air pollution and environmental justice impacts.

i.4.5 A refinery project disclosure question

Readers should note that P66[2] and MPC[11] excluded flares and hydrogen production which would be included in their proposed HEFA projects from emission reviews they assert in support of their air permit applications. To date neither refiner has disclosed whether or not its publicly asserted project emission estimate excludes any flare or hydrogen production plant emissions. However, as shown in Chapter 3, excluding flare emissions, hydrogen production emissions, or both could underestimate project emission impacts significantly.

i.5 The scope and focus of this report

This report addresses the questions and concerns introduced above. Its scope is limited to potential fuel chain and energy system impacts of HEFA technology crude-to-biofuel conversion projects. It focuses on the California setting and, within this setting, the Phillips 66 Co. (P66) Rodeo and Marathon Petroleum Corp. (MPC) Martinez projects. Details of the data and methods supporting original estimates herein are given in a Supporting Material Appendix.[1]

1. OVERVIEW OF HEFA BIOFUEL TECHNOLOGY

All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).[2] [3] [4] [6] "Hydrotreating" signifies a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: triacylglycerols (TAGs) and the fatty acids derived from TAGs. HEFA feedstock is biomass from the TAGs and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.

This chapter addresses how HEFA biofuel technology functions, which is helpful to assessing its potential impacts in the succeeding chapters, and explores why former and current crude oil refiners choose this technology instead of another available fuels production option.

1.1 HEFA process chemistry

Hydrocarbons formed in this process reflect the length of carbon chains in its feed. Carbon chain lengths of the fatty acids in the TAGs vary by feed source, but in oil crop and livestock fat feeds are predominantly in the range of 14–18 carbons (C14–C18) with the vast majority in the C16–C18 range.[1] Diesel is predominantly a C15–C18 fuel; Jet fuel C8–C16. The fuels HEFA can produce in relevant quantity are thus diesel and jet fuels, with more diesel produced unless more intensive hydrocracking is chosen intentionally to target jet fuel production.

HEFA process reaction chemistry is complex, and in practice involves hard-to-control process conditions and unwanted side-reactions, but its intended reactions proceed roughly in sequence to convert TAGs into distillate and jet fuel hydrocarbons.[12] [13] [14] [15] [16] [17] [18] [19] [20] [21] [22] Molecular sites of these reactions in the first step of HEFA processing, hydrodeoxygenation (HDO), are illustrated in Diagram 1 below.

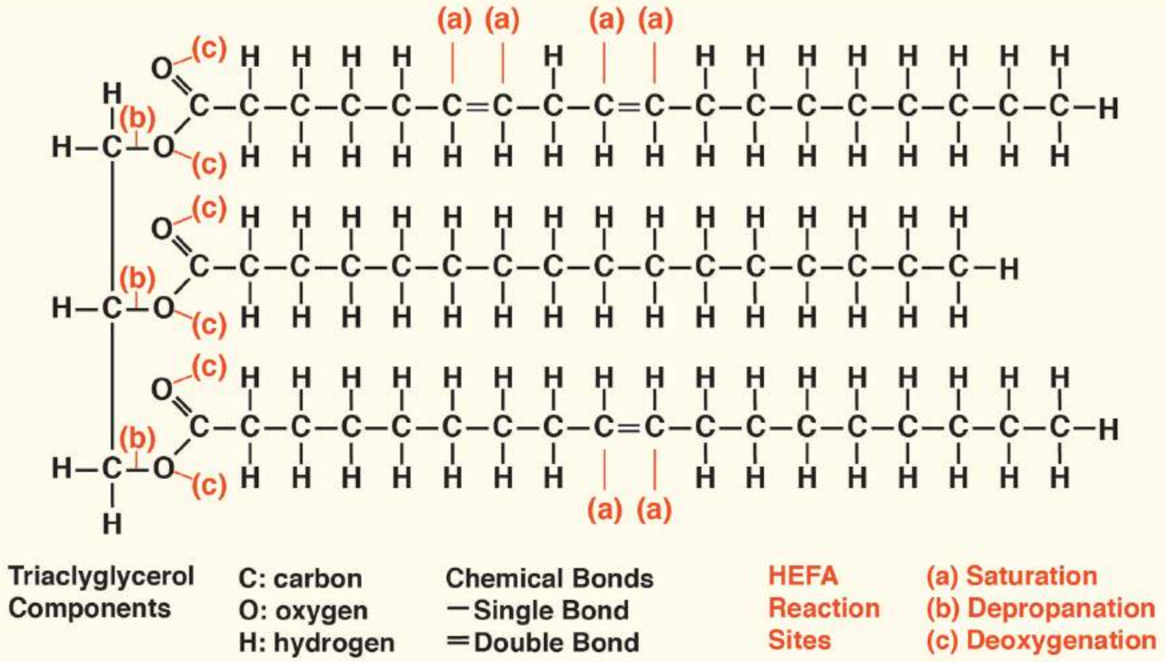


Diagram 1. Hydrodeoxygenation (HDO) of a triacylglycerol (TAG).

Fatty acids are "saturated" by bonding hydrogen to their carbon atoms. *See* (a) in Diagram. This tends to start first. Then, the fatty acids are broken free from the three-carbon "propane knuckle" of the TAG (Diagram 1, left) by breaking its bonds to them via hydrogen insertion. (Depropanation; *see* (b) in Diagram 1.) Still more hydrogen bonds with the oxygen atoms (c), to form water (H_2O), which is removed from the hydrocarbon process stream. These reactions yield water, propane, some unwanted but unavoidable byproducts (not shown in the diagram for simplicity), and the desired HDO reaction products—hydrocarbons which can be made into diesel and jet fuel.

But those hydrocarbons are not yet diesel or jet fuel. Their long, straight chains of saturated carbon make them too waxy. Fueling trucks or jets with wax is risky, and prohibited by fuel specifications. To de-wax them, those straight-chain hydrocarbons are turned into their branched-chain isomers.

Imagine that the second-to-last carbon on the right of the top carbon chain in Diagram 1 takes both hydrogens bonded to it, and moves to in between the carbon immediately to its left and one of the hydrogens that carbon already is bonded to. Now imagine the carbon at the end of the chain moves over to where the second-to-last carbon used to be, and thus stays attached to the carbon chain. That makes the straight chain into its branched isomer. It is isomerization.

Isomerization of long-chain hydrocarbons in the jet–diesel range is the last major HEFA process reaction step. Again, the reaction chemistry is complex, involves hard-to-control process conditions and unwanted side reactions at elevated temperatures and pressures, and uses a lot of hydrogen. But these isomerization reactions, process conditions, and catalysts are markedly different from those of HDO.[9 14–17 19 20] And these reactions, process conditions, catalysts and hydrogen requirements also depend upon whether isomerization is coupled with intentional hydrocracking to target jet instead of diesel fuel production.[1] Thus this last major set of HEFA process reactions has, so far, required a separate second step in HEFA refinery configurations. For example, MPC proposes to isomerize the hydrocarbons from its HDO reactors in a separate second-stage hydrocracking unit to be repurposed from its shuttered Martinez crude refinery.[3]

HEFA isomerization requires very substantial hydrogen inputs, and can recycle most of that hydrogen when targeting diesel production, but consumes much more hydrogen for intentional hydrocracking to boost jet fuel production, adding significantly to the already-huge hydrogen requirements for its HDO reaction step.[1]

The role and impact of heat and pressure in the HEFA process

Hydro-conversion reactions proceed at high temperatures and extremely high pressures. Reactors feeding gas oils and distillates of similar densities to HEFA reactor feeds run at 575–700 ºF and 600–2,000 pounds per square inch (psi) for hydrotreating and at 575–780 ºF and 600–2,800 psi for hydrocracking.[16] That is during normal operation. The reactions are exothermic: they generate heat in the reactor on top of the heat its furnaces send into it. Extraordinary steps to handle the severe process conditions become routine in hydro-conversion. Hydrogen injection and recycle capacities are oversized to quench and attempt to control reactor heat-and-pressure rise.[16 22] When that fails, which happens frequently as shown in a following chapter, the reactors depressurize, dumping their contents to emergency flares. That is during petroleum refining.

Hydro-conversion reaction temperatures increase in proportion to hydrogen consumption,[21] and HDO reactions can consume more hydrogen, so parts of HEFA hydro-conversion trains can run hotter than those of petroleum refineries, form more extreme "hot spots," or both. Indeed, HEFA reactors must be designed to depressurize rapidly.[22] Yet as of this writing, no details of design potential HEFA project temperature and pressure ranges have been reported publicly.

1.2 Available option of repurposing hydrogen equipment drives choice of HEFA

Refiners could choose better new biofuel technology

Other proven technologies promise more flexibility at lower feedstock costs. For example, Fischer-Tropsch synthesis condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce biogas, gasoline, jet fuel, or diesel biofuels.[23] Cellulosic biomass residues can be gasified for Fischer-Tropsch synthesis.[24] This alternative promises lower cost feedstock than HEFA technology and the flexibility of a wider range of future biofuel sales, along with the same ability to tap "renewable" fuel subsidies as HEFA technology. Refiners choose HEFA technology for a different reason.

Refiners can repurpose existing crude refining equipment for HEFA processing

Hydro-conversion reactors and hydrogen plants which were originally designed, built, and used for petroleum hydrocracking and hydrotreating could be repurposed and used for the new and different HEFA feedstocks and process reactions. This is in fact what the crude-to-biofuel refinery conversion projects propose to do in California.[2 3 5 6]

In the largest HEFA project to be proposed or built, P66 proposes to repurpose its 69,000 barrel/day hydrocracking capacity at units 240 and 246 combined, its 16,740 b/d Unit 248 hydrotreater, and its 35,000 b/d Unit 250 hydrotreater for 100% HEFA processing at Rodeo.[2 25] In the second largest project, MPC proposes to repurpose its 40,000 b/d No.2 HDS hydrotreater, 70,000 b/d No. 3 HDS hydrotreater, 37,000 b/d 1st Stage hydrocracker, and its 37,000 b/d 2nd Stage hydrocracker for 100% HEFA processing at Martinez.[3 26]

For hydrogen production to feed the hydro-conversion processing P66 proposes to repurpose 28.5 million standard cubic feet (SCF) per day of existing hydrogen capacity from its Unit 110 and 120 million SCF/d of hydrogen capacity from the Air Liquide Unit 210 at the same P66 Rodeo refinery.[2 25 27] MPC proposes to repurpose its 89 million SCF/d No. 1 Hydrogen Plant along with the 35 million SCF/d Air Products Hydrogen Plant No. 2 at the now-shuttered MPC Martinez refinery.[3 4 11 26]

By converting crude refineries to HEFA biofuel refiners protect otherwise stranded assets

Motivations to protect otherwise stranded refining assets are especially urgent in the two largest crude-to-biofuel refining conversions proposed to date. Uniquely designed and permitted to rely on a landlocked and fast-dwindling crude source already below its capacity, the P66 San Francisco Refinery has begun to shutter its front end in San Luis Obispo County, which makes its unheated pipeline unable to dilute and send viscous San Joaquin Valley crude to Rodeo.[28] This threatens the viability of its Rodeo refining assets—as the company itself has warned.[29] The MPC Martinez refinery was shut down permanently in a refining assets consolidation, possibly accelerated by COVID-19, though the pandemic closed no other California refinery.[30]

The logistics of investment in new and repurposed HEFA refineries as a refining asset protection mechanism leads refiners to repurpose a refining technology that demands hydrogen, then repurpose refinery hydrogen plants that supply hydrogen, then involve other companies in a related sector—such as Air Liquide and Air products—that own otherwise stranded hydrogen assets the refiners propose to repurpose as well.

Refiners also seek substantial public investments in their switch to HEFA biofuels. Tepperman (2020)[31] reports that these subsidies include federal “Blenders Tax” credits, federal “Renewable Identification Number” credits, and state “Low Carbon Fuel Standard” credits that one investment advisor estimated can total $3.32 per gallon of HEFA diesel sold in California. Krauss (2020)[32] put that total even higher at $4.00 per gallon. Still more public money could be directed to HEFA jet fuel, depending on the fate of currently proposed federal legislation.[33]

2. UPSTREAM — IMPACT OF FEEDSTOCK CHOICES

The types, amounts, and characteristics of energy feedstocks have repercussions across the energy system and environment. Choosing HEFA technology would lock into place a particular subset of the biomass carbon on our planet for use in energy production. It would further create a need for continued and potentially additional hydrogen use. This chapter evaluates the environmental impacts of feedstock acquisition and feedstock choices in HEFA production.

2.1 Proposed feedstock use by the Phillips 66, Marathon, and other California projects

2.1.1 Biomass volume

The proposed conversions at P66 and MPC, and attendant use of HEFA feedstocks, are very large in scale. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10] The feedstock capacity of its HEFA biorefinery proposed in Rodeo, CA reported by P66 is 80,000 barrels per day (b/d).[2] With a feedstock capacity of 48,000 b/d, the MPC Martinez, CA project could then be the second largest HEFA refinery to be proposed or built worldwide.[3] The World Energy subsidiary, AltAir, expansion in Paramount, CA, which also plans to fully convert a petroleum refinery, would add 21,500 b/d of new HEFA feedstock capacity.[5] And Global Clean Energy Holdings, Inc. plans to convert its petroleum refinery in Bakersfield, CA into a HEFA refinery[6] with at least 15,000 b/d of new capacity. Altogether that totals 164,500 b/d of new HEFA feedstock capacity statewide.

The aggregate proposed new California feedstock demand is some 61–132 *times* the annual feedstock demand for HEFA refining in California from 2016–2019.[34] But at the same time, the proposed new California biofuel feed demand is only ten percent of California refinery demand for crude oil in 2019,[35] the year before COVID-19 forced temporary refining rate cuts.[36] This raises a potential for the new HEFA feed demand from crude-to-biofuel refinery conversions proposed here today to be only the beginning of an exponentially increasing trend.

2.1.2 Biomass type

HEFA technology, proposed at all of the California refineries currently proposing conversion to biofuel production, uses as feedstock triacylglycerols (TAGs) and fatty acids derived from TAGs (Chapter 1). Primary sources of these biomass lipids in concentrations and amounts necessary for HEFA processing are limited to oil crop plants, livestock fats, and fish oils. Existing U.S. biofuels production has tapped soybean oil, distillers corn oil, canola oil, cottonseed oil, beef tallow, pork lard and grease, poultry fats, fish oils from an unreported and likely wide range of species, and used cooking oil—lipids that could be recovered from uses of these primary sources, also known as "yellow grease."[37] [38] [39]

2.1.3 Other uses for this type of biomass

Importantly, people already use these oils and fats for many other needs, and they are traded globally. Beside our primary use of this type of biomass to feed ourselves directly, we use it to feed livestock in our food system, to feed our pets, and to make soap, wax, lubricants, plastics, cosmetic products, and pharmaceutical products.[40]

2.2 Indirect impacts of feedstock choices

2.2.1 Land use and food system impacts

Growing HEFA biofuel feedstock demand is likely to increase food system prices. Market data show that investors in soybean and tallow futures have bet on this assumption.[41] [42] [43] This pattern of radically increasing feedstock consumption and the inevitable attendant commodity price increases threatens significant environmental and human consequences, some of which are already emerging even with more modestly increased feedstock consumption at present.

As early as 2008, Searchinger et al.[44] showed that instead of cutting carbon emissions, increased use of biofuel feedstocks and the attendant crop price increases could expand crop land into grasslands and forests, reverse those natural carbon sinks, and cause food-sourced biofuels to emit more carbon than the petroleum fuels they replace. The mechanism for this would be global land use change linked to prices of commodities tapped for both food and fuel.[44]

Refiners say they will not use palm oil, however, that alone does not solve the problem. Sanders et al. (2012)[45] showed that multi-nation demand and price dynamics had linked soy oil, palm oil, food, and biofuel feedstock together as factors in the deforestation of Southeast Asia for palm oil. Santeramo (2017)[46] showed that such demand-driven changes in prices act across the oil crop and animal fat feedstocks for HEFA biofuels in Europe and the U.S. Searle (2017)[47] showed rapeseed (canola) and soy biofuels demand was driving palm oil expansion; palm oil imports increase for other uses of those oils displaced by biofuels demand.

Additionally, The Union of Concerned Scientists (2015),[48] Lenfert et al. (2017),[49] and Nepstad and Shimada (2018)[50] linked soybean oil prices to deforestation for soybean plantations in the Brazilian Amazon and Pantanal. By 2017, some soy and palm oil biofuels were found to emit more carbon than the petroleum fuels they are meant to replace.[47 51] By 2019 the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES) warned large industrial biofuel feedstock plantations threaten global biodiversity.[52] By 2021 the Intergovernmental Panel on Climate Change joined the IPBES in this warning.[53] At high yields and prices, up to 79 million acres could shift to energy crops by 2030 in the U.S. alone.[40] And once a biofuel feedstock also used for food is locked in place, the human impacts of limiting land conversion could potentially involve stark social injustices, notably food insecurity and hunger.[44]

Work by many others who are not cited here contributed to better understanding the problem of our growing fuel chain-food chain interaction. Potential biodiversity loss, such as pollinator population declines, further risks our ability to grow food efficiently. Climate heating threatens more frequent crop losses. The exact tipping point, when pushing these limits too hard might turn the natural carbon sinks that biofuels depend upon for climate benefit into global carbon sources, remains unknown.

2.1.2 Impact on climate solutions

Technological, economic, and environmental constraints across the arrays of proven technologies and measures to be deployed for climate stabilization limit biofuels to a targeted role in sectors for which zero-emission fuels are not yet available.[53 54 55 56 57 58 59 60 61] And these technologies and measures require place-based deployment actions understood in a larger global context—actions that must be planned, implemented, and enforced by the political jurisdictions in each geography, but whose effect must be measured on a worldwide scale. California policy makers acted on this fact by expressly defining an in-state emission reduction which results in an emission increase elsewhere as inconsistent with climate protection.[62]

Tapping a biomass resource for biofuel feedstock can only be part of our state or national climate solution if it does not lead to countervailing climate costs elsewhere that wipe out or overtake any purported benefits. Thus, if California takes biomass from another state or nation which that other state or nation needs to cut emissions there, it will violate its own climate policy, and more crucially, burning that biofuel will not cut carbon emissions. Moreover, our climate policy should not come at the cost of severe human and environmental harms that defeat the protective purpose of climate policy.

Use of biofuels as part of climate policy is thus limited by countervailing climate and other impacts. Experts that the state has commissioned for analysis of the technology and economics of paths to climate stabilization suggest that state biofuel use should be limited to the per capita share of sustainable U.S. production of biofuel feedstock.[54 55] Per capita share is a valid benchmark, and is used herein, but it is not necessarily a basis for just, equitable, or effective policy. Per capita, California has riches, agriculture capacity, solar energy potential, and mild winters that populations in poorer, more arid, or more polar and colder places may lack. Accordingly, the per capita benchmark applied in Table 1 below should be interpreted as a conservative (high) estimate of sustainable feedstock for California HEFA refineries.

Table 1. U.S. and California lipid supplies *v.* potential new lipid feedstock demand from crude-to-biofuel refinery conversions now planned in California.

***MM t/y:** million metric tons/year*

Lipids supply	U.S. (MM t/y)	 (%)	CA per capita [d] (MM t/y)	CA produced [e] (MM t/y)
Biofuels [a]	4.00	100 %	0.48	0.30
All uses	20.64	100 %	2.48	1.55
Soybean oil [b]	10.69	52 %		
Livestock fats [a]	4.95	24 %		
Corn oil [b]	2.61	13 %		
Waste oil [a]	1.40	7 %		
Canola oil [b]	0.76	4 %		
Cottonseed [b]	0.23	1 %		

Lipids Demand for four proposed CA refineries	Percentage of U.S. and California supplies for all uses		
(MM t/y) [c]	U.S. total	CA per capita	CA produced
8.91	43 %	359 %	575 %

a. US-produced supply of feedstocks for hydro-processing esters and fatty acids (HEFA) in 2030, estimated in the U.S. Department of Energy *Billion-Ton Update* (2011).[40] Includes total roadside/farm gate yields estimates in the contiguous U.S. for biofuel feedstock consumption, and for all uses of animal fats and waste oil (used cooking oil).
b. U.S. farm yield for all uses of lipids used in part for biofuels during Oct 2016–Sep 2020 from U.S. Department of Agriculture *Oil Crops Data: Yearbook Tables;* tables 5, 20, 26 and 33.[38] *See* also Karras (2021a).[63]
c. From proposed Rodeo,[2] Martinez,[3] Paramount[5] and Bakersfield[6] capacity at a feed specific gravity of 0.914.
d. California per capita share of U.S. totals based on 12 percent of the U.S. population.
e. Calif. produced lipids, after *Billion-Ton Update* by Mahone et al.,[55] with lipids for all uses scaled proportionately.

2.3 Effect of supply limitations on feedstock acquisition impacts

Feeding the proposed new California HEFA refining capacity could take more than 350% of its per capita share from total U.S. farm yield for *all uses* of oil crop and livestock fat lipids that have been tapped for biofuels in much smaller amounts until now. See Table 1. The 80,000 b/d (~4.24 MM t/y) P66 Rodeo project[2] alone could exceed this share by ~71%. At 128,000 b/d (~6.79 MM t/y) combined, the P66[2] and Marathon[3] projects together could exceed it by ~174%.

2.3.1 Supply effect on climate solutions

Emission shifting would be the first and most likely impact from this excess taking of a limited resource. The excess used here could not be used elsewhere, and use of the remaining farmed lipids elsewhere almost certainly would prioritize food. Reduced capacity to develop and use this biofuel for replacing petroleum diesel outside the state would shift future emissions.

2.3.2 Supply effect on land use and food systems

Displacement of lipid food resources at this scale would also risk cascading impacts. These food price, food security, and land conversion impacts fuel deforestation and natural carbon sink destruction in the Global South, and appear to have made some HEFA biofuels more carbon-intensive than petroleum due to indirect land use impacts that diminish the carbon storage capacity of lands converted to biofuel plantations, as described above.[41–53]

The severity of these risks to food security, biodiversity, and climate sinks appears uncertain for some of the same reasons that make it dangerous. Both the human factors that drove land use impacts observed in the past[41–53] and the ecological resilience that constrained their severity in the past may not always scale in a linear or predictable fashion, and there is no precedent for the volume of lipid resource displacement for energy now contemplated.

In contrast, the causal trigger for any or all of these potential impacts would be a known, measurable volume of potential lipid biomass feedstock demand. Importantly, this volume-driven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively by separate policy or investment actions.

2.3.3 Supply effect on HEFA feedstock choices

Both Marathon and P66 have indicated informally that their preferred feedstocks are used cooking oil "waste" and domestic livestock fats rather than soy and other food crop oils. It is clear, however, that supplies of these feedstocks are entirely insufficient to meet anticipated demand if the two conversions (and the others planned in California) move forward. Table 1 reveals the fallacy of assuming that used "waste" cooking oil or domestic livestock fats could feed the repurposed HEFA refineries, showing that supplies would be inadequate even in an extreme hypothetical scenario wherein biofuel displaces all other uses of these lipids.

As discussed below, these HEFA feedstock availability limitations have fuel chain repercussions for the other critical HEFA process input—hydrogen.

2.4 Impact of biomass feedstock choices on hydrogen inputs

2.4.1 All HEFA feedstocks require substantial hydrogen inputs to convert the triacylglycerols and fatty acids in the lipid feedstock into HEFA biofuels

Hydrogen (H_2) is the most abundant element in diesel and jet fuel hydrocarbons, and all of the lipid feedstocks that HEFA refiners could process need substantial refinery hydrogen inputs. In HEFA refining hydrogen bonds with carbon in lipid feeds to saturate them, to break the fatty acids and propane "knuckle" of those triacylglycerols apart, and—in unavoidable side-reactions or intentionally to make more jet fuel—to break longer carbon chains into shorter carbon chains. (Chapter 1.) Hydrogen added for those purposes stays in the hydrocarbons made into fuels; it is a true HEFA biofuel feedstock.

Hydrogen also bonds with oxygen in the lipids to remove that oxygen from the hydrocarbon fuels as water. *Id.* Forming the water (H_2O) takes two hydrogens per oxygen, and the lipids in HEFA feedstocks have consistently high oxygen content, ranging from 10.8–11.5 weight percent,[1] so this deoxygenation consumes vast amounts of hydrogen. Further, hydrogen is injected in large amounts to support isomerization reactions that turn straight-chain hydrocarbons into branched-chain hydrocarbons. (Chapter 1.) And more hydrogen is injected to quench and control severe processing conditions under which all of these hydro-conversion reactions proceed. *Id.*

2.4.2 Some HEFA feedstocks need more hydrogen for HEFA processing than others

All types of HEFA feeds consume hydrogen in all the ways described above. However, how much is consumed in the first reaction—saturation—depends on the number of carbon double bonds in the fatty acids of the specific lipid feed source. *See* Diagram 1, Chapter 1. That matters because fatty acids in one specific HEFA lipids feed can have more carbon double bonds than fatty acids in another. Charts 1-A through 1–F below illustrate these differences in the fatty acid profiles of different HEFA feeds. The heights of the columns in these charts show the percentages of fatty acids in each feed that have various numbers of carbon double bonds.

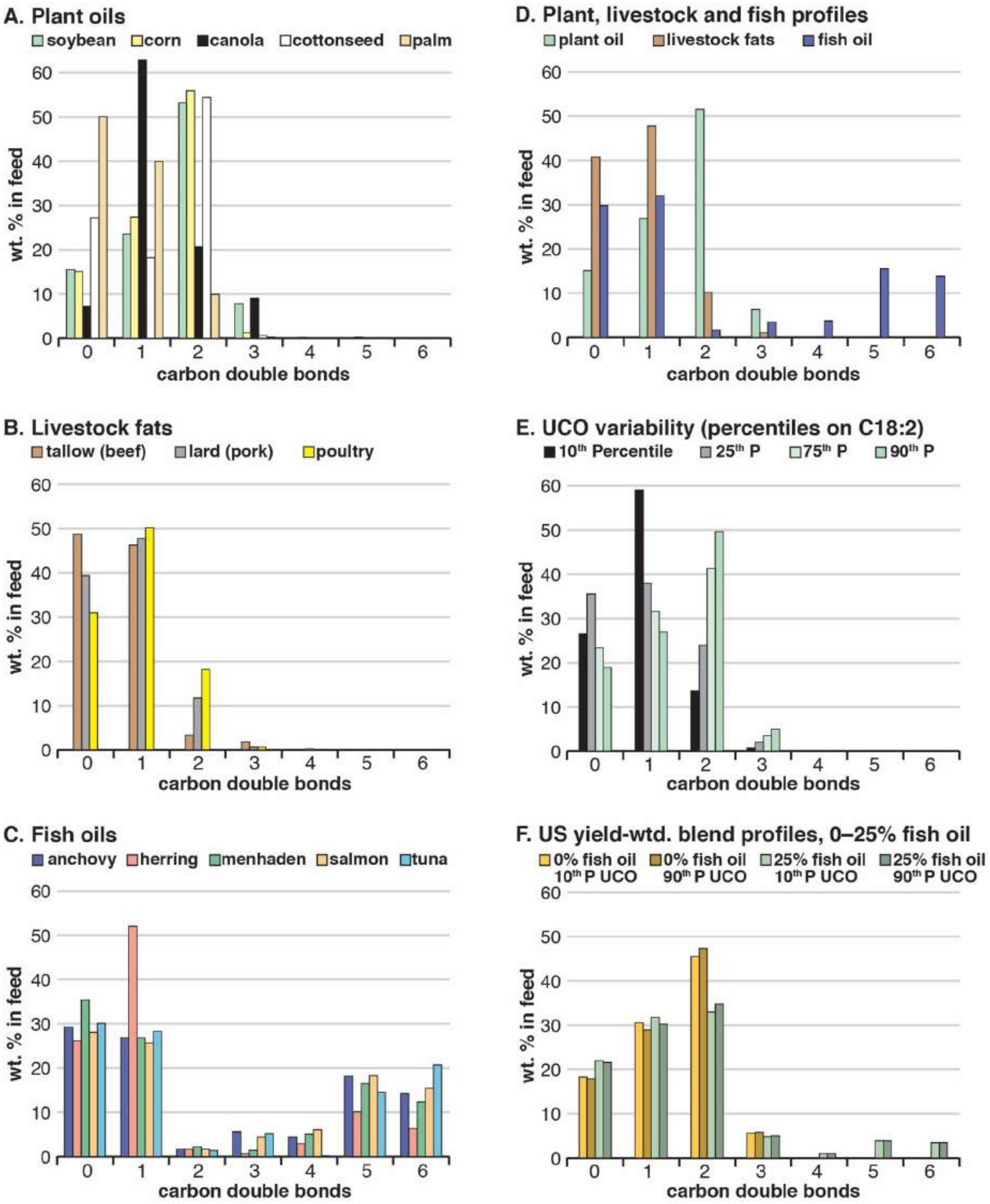
In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock fat profiles, which are essentially empty on the right side of charts 1-A and 1-B, a significant portion of the fatty acids in fish oils have 4–6 carbon double bonds (Chart 1-C).

Thus, HEFA processing requires more hydrogen to saturate the carbon double bonds in soy oil than those in livestock fats, and even more hydrogen to saturate those in fish oils. Such single-feed contracts are plausible, but feedstock acquisition logistics for the HEFA biofuels expansion—especially in light of the supply problem shown in Table 1—suggest refiners will process blends, and likely will process yield-weighted blends. Charts 1-D and 1-F show that such blends would dampen but still reflect these differences between specific plant oils, livestock fats, and fish oils. Finally, Chart 1-E illustrates the notoriously variable quality of used cooking oil (UCO), and Chart 1-F illustrates how the impact of UCO variability could be small compared with the differences among other feeds, since UCO could be only a small portion of the blend, as shown in Table 1.

2.4.3 Refining HEFA feedstocks demands more hydrogen than refining crude oil

Table 2, on the next page following the charts below, shows total hydrogen demand per barrel of feedstock, for processing different HEFA feeds, and for targeting different HEFA fuels.

Hydrogen demand for saturation of carbon double bonds ranges across the biomass feeds shown in Table 2 from 186–624 standard cubic feet of H_2 per barrel of biomass feed (SCF/b), and is the largest feedstock-driven cause of HEFA H_2 demand variability. For comparison, total on-purpose hydrogen production for U.S. refining of petroleum crude from 2006–2008, before lighter shale oil flooded refineries, averaged 273 SCF/b.[1] [64] This 438 (624-186) SCF/b saturation range alone exceeds 273 SCF/b. The extra H_2 demand for HEFA feeds with more carbon double bonds is one repercussion of the livestock fat and waste oil supply limits revealed in Table 1.



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]

Table 2. Hydrogen demand for processing different HEFA biomass carbon feeds.

Standard cubic feet of hydrogen per barrel of biomass feed (SCF/b)

	Hydrodeoxygenation reactions		Total with isomerization / cracking	
Biomass carbon feed	Saturation[a]	Others[b,c]	Diesel target	Jet fuel target[d]
Plant oils				
Soybean oil	479	1,790	2,270	3,070
Plant oils blend[e]	466	1,790	2,260	3,060
Livestock fats				
Tallow	186	1,720	1,910	2,690
Livestock fats blend[e]	229	1,720	1,950	2,740
Fish oils				
Menhaden	602	1,880	2,480	3,290
Fish oils blend[e]	624	1,840	2,460	3,270
US yield-weighted blends[e]				
Blend without fish oil	438	1,780	2,220	3,020
Blend with 25% fish oil	478	1,790	2,270	3,070

a. Carbon double bond saturation as illustrated in Diagram 1 (a). **b, c.** Depropanation and deoxygenation as illustrated in Diagram 1 (b), (c), and losses to unwanted (diesel target) cracking, off-gassing and solubilization in liquids. **d.** Jet fuel total also includes H_2 consumed by intentional cracking along with isomerization. **e.** Blends as shown in charts 1-D and 1-F. Data from Tables A1and Appendix at A2.[1] Figures may not add due to rounding.

Moreover, although saturation reaction hydrogen alone can exceed crude refining hydrogen, total hydrogen consumption in HEFA feedstock processing is larger still, as shown in Table 2.

Other hydrodeoxygenation reactions—depropanation and deoxygenation—account for most of the total hydrogen demand in HEFA processing. The variability in "other" hydrogen demand mainly reflects unavoidable hydrogen losses noted in Table 2, which rise with hydro-conversion intensity. Targeting maximum jet fuel rather than diesel production boosts total HEFA hydrogen demand by approximately 800 SCF/b.[1 9 65] This is primarily a product slate rather than feed-driven effect: maximizing jet fuel yield from the HDO reaction hydrocarbons output consumes much more hydrogen for intentional hydrocracking, which is avoided in the isomerization of a HEFA product slate targeting diesel.

Total hydrogen demand to process the likely range of yield-weighted biomass blends at the scale of planned HEFA expansion could thus range from 2,220–3,070 SCF/b, fully 8–11 *times* that of the average U.S. petroleum refinery (273 SCF/b).[1 64] This has significant implications for climate and community impacts of HEFA refining given the carbon-intensive and hazardous ways that refiners already make and use hydrogen now.

3. MIDSTREAM — HEFA PROCESS ENVIRONMENTAL IMPACTS

This chapter assesses refinery carbon emissions, refinery explosion and fire hazards, and air pollution impacts from refinery flares in HEFA processing. As shown in Chapter 2, turning a petroleum refinery into a HEFA refinery increases its hydrogen input intensity. This increased hydrogen intensity is particularly problematic given that the proposed conversions are all based on plans to re-purpose existing fossil fuel hydrogen production and hydro-conversion processes (Chapter 1). Current refinery hydrogen production that refiners propose to re-purpose uses the extraordinarily carbon intense “steam reforming” technology. Additionally, refinery explosion, fire, and flare emission hazards associated with processing in hydro-conversion units which refiners propose to re-purpose intensify at the increased hydrogen feed rates HEFA processing requires. P66 proposes to repurpose 148.5 million standard cubic feet per day (MMSCFD) of existing steam reforming hydrogen production capacity and 120,740 barrels per day (b/d) of existing hydro-conversion capacity for its proposed HEFA refinery in Rodeo. *Id.* MPC proposes to repurpose 124 MMSCFD of steam reforming capacity and 147,000 b/d of hydro-conversion capacity for its proposed HEFA refinery in Martinez. *Id.*

3.1 Carbon impact of steam reforming in the HEFA process

The hydrogen intensity of HEFA processing makes emissions from supplying the hydrogen all the more important, and as noted, refiners propose to repurpose carbon-intensive steam reforming. This could boost HEFA refinery carbon emissions dramatically.

Steam reforming makes hydrogen by stripping it from hydrocarbons, and the carbon left over from that forms carbon dioxide (CO_2) that emits as a co-product. See Diagram 2. It is often called methane reforming, but refiners feed it other refining byproduct hydrocarbons along with purchased natural gas, and even more CO_2 forms from the other feeds. The difference illustrated in Diagram 2 comes out to 16.7 grams of CO_2 per SCF of H_2 produced from propane *versus* 13.9 grams CO_2/SCF H_2 produced from methane. Fossil fuel combustion adds more CO_2.

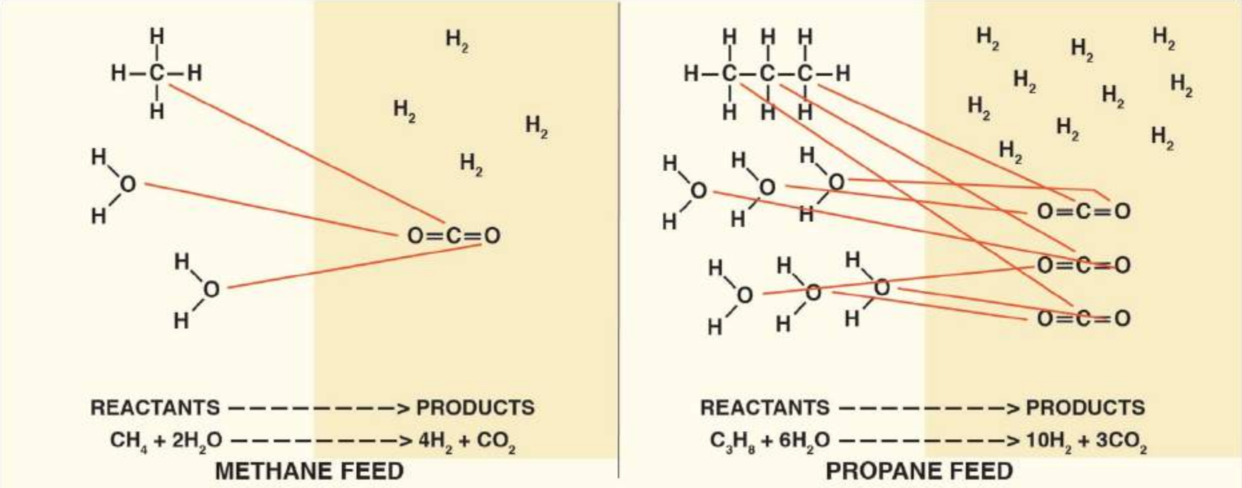


Diagram 2. Hydrogen steam reforming: reforming and shift reactions.
As the reforming and shift reactions produce hydrogen (H_2) from the hydrogen atoms (H) in hydrocarbons and steam, they bond the left-over carbon (C) and oxygen (O) atoms in those reactants together to form carbon dioxide (CO_2). This emits more CO_2 per H_2 produced from hydrocarbons with more carbon atoms.

Heating the water and feed to make the mixture of superheated steam and hydrocarbons that react at 1,300–1,900 ºF, and making the additional steam and power that drive its pumps and pressure, make steam reforming energy intensive. Natural gas and refinery process off gas burn for that energy. Combustion energy intensity, based on design capacities verified and permitted by local air officials, ranges across 11 hydrogen plants that serve or served Bay Area refineries, from 0.142–0.277 million joules (MJ) per SCF H_2 produced, with a median of 0.202 MJ/SCF across the 11 plants.[1] At the median, ~10 gCO_2/SCF H_2 produced emits from burning methane. That, plus the 13.9 g/SCF H_2 from methane feed, could emit 23.9 g/SCF. This median energy intensity (EI) for methane feed is one of the potential plant factors shown in Table 3 below.

Hydrogen plant factors are shown in Table 3 for two feeds—methane, and a 77%/23% methane/propane mix—and for two combustion energy intensities, a Site EI and the median EI from Bay Area data discussed above. The mixed feed reflects propane by-production in HEFA process reactions and the likelihood that this and other byproduct gases would be used as feed, fuel, or both. Site EI should be more representative of actual P66 and MPC plant factors, but details of how they will repurpose those plants have not yet been disclosed. Median EI provides a reference point for P66 and MPC plant factors, and is applied to the other projects in the statewide total at the bottom of the table.

Table 3 shows how high-carbon hydrogen technology and high hydrogen demand for hydroconversion of HEFA feeds (Chapter 2) combine to drive the carbon intensity of HEFA refining. At the likely hydrogen feed mix and biomass feed blend lower bound targeting diesel production, HEFA hydrogen plants could emit 55.3–57.9 kilograms of CO_2 per barrel of biomass feed. And in those conditions at the upper bound, targeting jet fuel, they could emit 76.4–80.1 kg/b.

Table 3. CO_2 emissions from hydrogen production proposed for HEFA processing by full scale crude-to-biofuel refinery conversions planned in California.

g: gram (CO_2) **SCF:** standard cubic foot (H_2) **b:** barrel (biomass feed) **Mt:** million metric tons

	Plant factor[a] (g/SCF)	Conversion demand (SCF/b)[b]		Carbon intensity (kg/b)	Mass emission[c] (Mt/y)
		Lower bound	Upper bound		
P66 Rodeo					
Mixed feed [d]					
Site EI [a]	26.1	2,220	3,070	57.9 – 80.1	1.69 – 2.34
Median EI [a]	24.9	2,220	3,070	55.3 – 76.4	1.61 – 2.23
Methane [d]					
Site EI [a]	25.0	2,220	3,070	55.5 – 76.7	1.62 – 2.24
Median EI [a]	23.9	2,220	3,070	53.1 – 73.4	1.55 – 2.14
MPC Martinez					
Mixed feed [d]					
Site EI [a]	25.8	2,220	3,070	57.3 – 79.2	1.00 – 1.39
Median EI [a]	24.9	2,220	3,070	55.3 – 76.4	0.97 – 1.34
Methane [d]					
Site EI [a]	24.7	2,220	3,070	54.8 – 75.8	0.96 – 1.33
Median EI [a]	23.9	2,220	3,070	53.1 – 73.4	0.93 – 1.29
Total CA Plans: P66, MPC, AltAir and GCE					
Mixed feed [a, d]	25.8	2,220	3,070	57.3 – 79.2	3.51 – 4.86
Methane [a, d]	24.6	2,220	3,070	54.6 – 75.5	3.35 – 4.63

a. Plant factor energy intensity (EI) expressed as emission rate assuming 100% methane combustion fuel. Site EI is from plant-specific, capacity-weighted data; median EI is from 11 SF Bay Area hydrogen plants that serve or served oil refineries. CA total assumes site EIs for P66 and MPC and median EI for AltAir and GCE. **b.** H_2 demand/b biomass feed: lower bound for yield-weighted blend with 0% fish oil targeting maximum diesel production; upper bound for yield-weighted blend with 25% fish oil targeting maximum jet fuel production. **c.** Mass emission at kg/b value in table and capacity of proposed projects, P66: 80,000 b/d; MPC: 48,000 b/d; Altair: 21,500 b/d; GCE: 18,500 b/d. **d.** Mixed feed is 77% methane and 23% propane, the approximate proportion of propane by-production from HEFA processing, and the likely disposition of propane, other process byproduct gases, or both; methane: 100% methane feed to the reforming and shift reactions. *See* Appendix for details.[1]

Total CO_2 emissions from hydrogen plants feeding the currently proposed HEFA refining expansion proposed statewide could exceed 3.5 million tons per year—if the refiners only target diesel production. *See* Table 3. If they all target jet fuel, and increase hydrogen production to do so, those emissions could exceed 4.8 million tons annually. *Id.*

It bears note that this upper bound estimate for targeting jet fuel appears to require increases in permitted hydrogen production at P66 and MPC. Targeting jet fuel at full feed capacity may also require new hydrogen capacity a step beyond further expanding the 1998 vintage[66] P66 Unit 110 or the 1963 vintage[67] MPC No. 1 Hydrogen Plant. And if so, the newer plants could be less energy intensive. The less aged methane reforming merchant plants in California, for example, have a reported median CO_2 emission rate of 76.2 g/MJ H_2.[68] That is 23.3 g/SCF, close to, but less than, the methane reforming median of 23.9 g/SCF in Table 3. Conversely, the belief, based on available evidence until quite recently, that methane emissions from steam reformers do not add significantly to the climate-forcing impact of their huge CO_2 emissions, might turn out to be wrong. Recently reported aerial measurements of California refineries[69] indicate that methane emissions from refinery hydrogen production have been underestimated dramatically. Thus, the upper bound carbon intensity estimates in Table 3 might end up being too high or too low. But questions raised by this uncertainty do not affect its lower bound estimates, and those reveal extreme-high carbon intensity.

Total CO_2 emissions from U.S. petroleum refineries averaged 41.8 kg per barrel crude feed from 2015–2017, the most recent period in which we found U.S. government-reported data for oil refinery CO_2 emitted nationwide.[1] At 55–80 kg per barrel biomass feed, the proposed HEFA hydrogen production *alone* exceeds that petroleum refining carbon intensity by 32–91 percent.

Additional CO_2 would emit from fuel combustion for energy to heat and pressure up HEFA hydro-conversion reactors, precondition and pump their feeds, and distill, then blend their hydrocarbon products. Unverified potential to emit calculations provided by one refiner[1] suggest that these factors could add ~21 kg/b to the 55–80 kg/b from HEFA steam reforming. This ~76–101 kg/b HEFA processing total would exceed the 41.8 kg/b carbon intensity of the average U.S. petroleum refinery by ~82–142 percent. Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing.

3.2 Local risks associated with HEFA processing

HEFA processing entails air pollution, health, and safety risks to workers and the surrounding community. One of these risks—the intensified catastrophic failure hazard engendered by the more intensive use of hydrogen for HEFA processing—renders HEFA refining in this respect more dangerous than crude processing.

3.2.1 HEFA processing increases refinery explosion and fire risk

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.[70] The oil industry knew that introducing a new and different crude into an existing refinery can introduce new hazards.[71] 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 it now proposes to repurpose for HEFA biomass feeds,[71] and feedstock changes are among the most frequent causes of dangerous upsets in these hydro-conversion reactors.[16]

But differences between the new biomass feedstock refiners now propose and crude oil are bigger 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.[70]

Chevron Richmond Refinery, 6 Aug 2012. Image: CSB

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."[71] At 10.8–11.5 wt. %, HEFA feeds have very high oxygen content,[1] while the petroleum crude fed to refinery processing has virtually none. Carbonic acid forms from that oxygen in HEFA processing. Carbonic acid corrosion is a known hazard in HEFA processing.[22] 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[71] cannot reliably guide—and could misguide—refiners that attempt to find, then fix, damage from this new hazard before it causes equipment failures.

Worse, high-oxygen HEFA feedstock boosts hydrogen consumption in hydro-conversion reactors dramatically, as shown in Chapter 2. 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.

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.[16 21 22] When they consume more hydrogen, they generate more heat.[21] Then they get hotter, and crack more of their feed, consuming even more hydrogen,[16][21] so “the hotter they get, the faster they get hot.”[16] And the reactions proceed at extreme pressures of 600–2,800 pound-force per square inch,[16] 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[16]—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.

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.[22] And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.

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.

Significant and sometimes catastrophic incidents involving the types of hydrogen processing systems proposed for California HEFA projects are unfortunately common in crude oil refining, as reflected in the following incident briefs posted by *Process Safety Integrity*[72] 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 MPC) 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.[72]

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.

Refiners have the ability to use extra hydrogen to quench, control, and guard against runaway reactions as described in Chapter 1, 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.[16] [22] 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. 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. *See* Table 4 for specific examples.

Indeed, 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 P66 Rodeo and MPC Martinez refineries frequently. Causal analysis reports for significant flaring show that hydrogen-related hazard incidents occurred at those refineries a combined total of 100 times from January 2010 through December 2020.[1] This is a conservative estimate, since incidents can cause significant impacts without causing environmentally significant flaring, but still represents, on average, and accounting for the Marathon plant closure since April 2020, another hydrogen-related incident at one of those refineries every 39 days.[1]

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.[1] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[1] 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.[1]

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.

Table 4. Examples from 100 hydrogen-related process hazard incidents at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020.

Date [a]	Refinery	Hydrodrogen-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 Regulation § 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 given in Table A6 of this report. Notes b–k below further illustrate 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."

3.2.2 HEFA processing would perpetuate localized episodic air pollution

Refinery flares are episodic air polluters. Every time the depressurization-to-flare safeguard dumps process gases in attempts to avoid even worse consequences, that flaring is uncontrolled open-air combustion. Flaring emits a mix of 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 incidents described above flared more than two million cubic feet of vent gas each, and many flared more than ten million.[1]

The increased risk of process upsets associated with HEFA processing concomitantly creates increased risk to the community of acute exposures to air pollutants, with impacts varying with the specifics of the incident and atmospheric conditions at the time when flaring recurs.

In 2005, flaring was linked to episodically elevated local 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.[73] By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.[74] [75] These same significance thresholds were used to require P66 and MPC to report the hazard data described above.[75]

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the P66 Rodeo and MPC Martinez refineries discussed above *individually* exceeded a relevant environmental significance threshold for air quality. Therefore, by prolonging the time over which the frequent incidents continue, and likely increasing the frequency of this significant flaring, repurposing refineries for HEFA processing can be expected to cause significant episodic air pollution.

Environmental justice impacts

It bears significant note that the refinery communities currently living with episodic air pollution—which would potentially be worsened by the conversion to HEFA processing—are predominantly populated by people of color. In fact, refineries were found to account for 93% of the statewide population-weighted disparity between people of color and non-Hispanic whites in particulate matter emission burdens associated with all stationary source industries in the state cap-and-trade program.[76] These communities of color tend to suffer from a heavy pre-existing pollution burden, such that additional and disproportionate episodic air pollution exposures would have significant environmental justice implications.

4. DOWNSTREAM — IMPACT OF BIOFUEL CONVERSIONS ON CLIMATE PATHWAYS

This chapter assesses potential impacts of HEFA biofuels expansion on California climate plans and goals. Primary issues of concern are HEFA biofuel volume, total liquid combustion fuel volume, systemic effects of refining and hydrogen use which could create HEFA lock-in, and the timing of choices between zero-emission *versus* liquid combustion fuels. Benchmarks for assessing these impact issues are taken from state roadmaps for the array of decarbonization technologies and measures to be deployed over time to achieve state climate goals—herein, "climate pathways." The state has developed a range of climate pathways, which rely in large part on strategies for replacing petroleum with zero-emission fuels that HEFA growth may disrupt and which reflect, in part, tradeoffs between zero-emission and liquid combustion fuels. Section 4.1 provides background on these climate pathway benchmarks and strategies.

Section 4.2 compares a foreseeable HEFA growth scenario with state climate pathway benchmarks for HEFA biofuel volume, total liquid fuel volume and systemic effects of refining and hydrogen use through mid-century, and estimates potential greenhouse gas emissions. This assessment shows that HEFA biofuel growth has the potential to impact state climate goals significantly. Section 4.3 addresses the timing of choices between zero-emission and liquid combustion fuels, shows that a zero-emission hydrogen alternative could be deployed during a critical window for breaking carbon lock-in, and assesses HEFA growth impacts on the emission prevention, clean fuels development, and transition mitigation effectiveness of this alternative.

4.1 California climate goals and implementation pathway benchmarks background related to HEFA biofuel impact issues assessed

4.1.1 State climate goals and pathways that HEFA biofuels growth could affect

State climate goals call for cutting greenhouse gas emissions 80% below 1990 emissions to a 2050 target of 86.2 million tons per year,[77] for zero-emission vehicles (ZEVs) to be 100% of light-duty vehicle (LDV) sales by 2035 and 100% of the medium- and heavy-duty vehicle (MDV and HDV) fleet by 2045,[78] and for achieving net-zero carbon neutrality by 2045.[79]

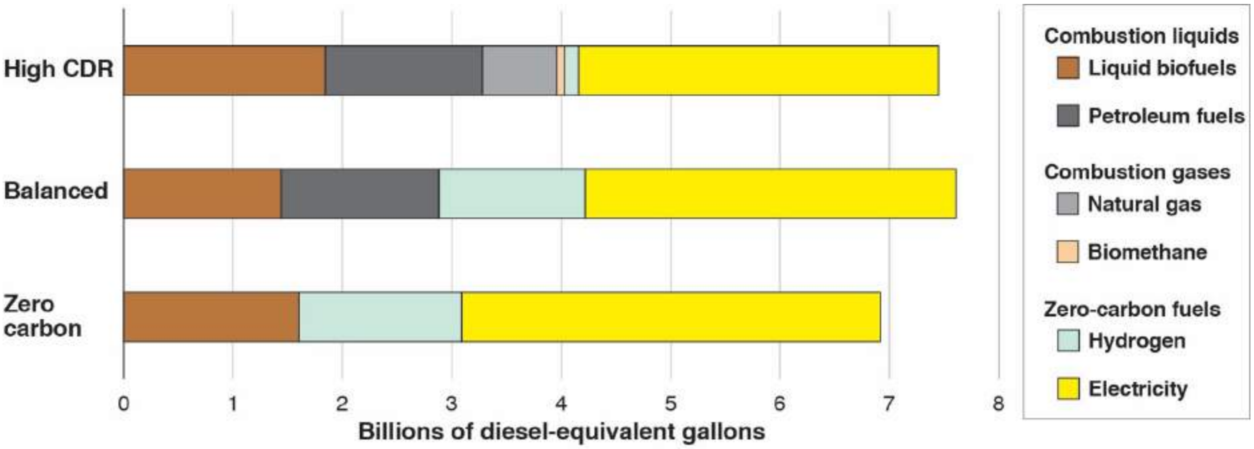
Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by developing climate pathways that range from near-zero carbon to high-CDR. These pathways show how various types of biofuels and other technologies and measures fit into lower-emission and higher-emission approaches to achieving state climate goals.

Pathway scenarios developed by Mahone et al. for the California Energy Commission (CEC),[54] Air Resources Board[55] and Public Utilities Commission,[56] Austin et al. for the University of California,[57] and Reed et al. for UC Irvine and the CEC[58] add semi-quantitative benchmarks to the 2050 emission target, for assessing refinery conversions to biofuels. They join other work in showing the need to decarbonize electricity and electrify transportation.[54–61] Their work "bookends" the zero-carbon to high–CDR range of paths to state climate goals,[55] analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,[54–58] and addresses potential biomass fuel chain effects on climate pathways.[54 55 57]

4.1.2 State climate pathway liquid fuels volume benchmarks that HEFA biofuels growth could affect

Total liquid transportation fuels benchmark: ~1.6 to 3.3 billion gallons by 2045

All state pathways to net-zero emissions cut liquid petroleum fuels use dramatically, with biofuels replacing only a portion of that petroleum. Chart 2 illustrates the "bookends" of the zero-carbon to high-CDR range of pathways for transportation reported by Mahone et al.[55]



2. California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.

Adapted from Figure 8 in Mahone et al. (2020a[55]). Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).

Total liquid hydrocarbon combustion fuels for transportation in 2045, including petroleum and biofuels, range among the pathways from approximately 1.6 to 3.3 billion gallons/year (Chart 2), which is roughly 9% to18% of statewide petroleum transportation fuels use from 2013–2017.[55] Liquid biofuels account for approximately 1.4 to 1.8 billion gallons/year, which is roughly 40% to 100% of liquid transportation fuels in 2045 (Chart 2). Importantly, up to 100% of the biofuels in these pathways would be derived from cellulosic biomass feedstocks[57 80 81] instead of purpose-grown lipids which HEFA technology relies upon, as discussed below.

HEFA biofuels volume benchmark: zero to 1.5 billion gallons per year through 2045

Many State climate pathways exclude or cap HEFA biofuel. Mahone et al. assume biofuels included in the pathways use cellulosic residues that are not purpose-grown—and cap those fuels in most scenarios to the per capita state share of non-purpose-grown U.S. biomass supply.[54 55] This excludes purpose-grown lipids-derived biofuels such as the HEFA biofuels. Austin et al.[57] assume a cap on lipids biomass that limits HEFA jet fuel and diesel use to a maximum of 0.5–0.6 and 0.8–0.9 billion gallons/year, respectively. Both Austin[57] and Mahone[54 55] cite difficult-to-predict land use emissions as reasons to limit purpose-grown crop and lipid-derived biofuels *as pathway development constraints* rather than as problems with the Low Carbon Fuel Standard (LCFS). This report agrees with that view: the need and ability to limit HEFA volume is a climate pathway impact issue—and local land use impact issue—not a criticism of the LCFS. *See* Box below.

4.1.3 Electrolysis hydrogen benchmarks for systemic energy integration that affect the timing of choices between zero-emission *versus* liquid combustion fuels

To replace combustion fuels in hard-to-electrify sectors, state climate pathways rely in part on "energy integration" measures, which often rely on electrolysis hydrogen, as discussed below.

Hydrogen for hard-to-decarbonize energy uses

Hydrogen, instead of HEFA diesel, could fuel long-haul freight and shipping. Hydrogen stores energy used to produce it so that energy can be used *where* it is needed for end-uses of energy that are hard to electrify directly, and *when* it is needed, for use of solar and wind energy at night and during calm winds. Climate pathways use hydrogen for hard-to-electrify emission sources in transportation, buildings and industry, and to support renewable electricity grids.

What is renewable-powered electrolysis hydrogen?

Electrolysis produces hydrogen from water using electricity. Oxygen is the byproduct, so solar and wind-powered electrolysis produces zero-emission hydrogen. State climate pathways consider three types of electrolysis: alkaline, proton-exchange membrane, and solid oxide electrolyzers.[55 58] The alkaline and proton-exchange membrane technologies have been proven in commercial practice.[58] Renewable-powered electrolysis plants are being built and used at increasing scale elsewhere,[82] and California has begun efforts to deploy this technology.[58]

Biofuels in the Low Carbon Fuel Standard (LCFS)

What the LCFS does	What we still need to do in other ways
Reduces the carbon intensity (CI) of transportation fuels	Reduce carbon-based fuel volume and volume-related mass emissions
Reduces transportation fuels CI by increments, over increments of time	Avoid committing to fuels that would exceed 2045 climate targets despite early incremental CI cuts
Moves money from higher-CI to lower-CI fuel producers	Build long-lasting production only for those fuels which will not exceed 2045 climate targets
Applies to fuels sold for use in the state, including biofuels, fossil fuels, electricity and hydrogen fuels	Prevent imports that people elsewhere need for their own biomass-based food and fuel
Compares the CI of each biofuel to the CI of the petroleum fuel it could replace across the whole fuel chains of both. To move dollars from higher to lower CI fuel producers, a specific “lifecycle” CI number estimate is made for each biofuel, from each type of biomass production, biofuel production, and fuel combustion in transportation for that biofuel	Directly monitor all the worldwide interactions of biomass fuel and food chains—to find out *before* an impact occurs. For example, what if increasing demand for soy-based biofuel leads farmers to buy pastureland for soybean plantations, leading displaced ranchers to fell rainforest for pastureland in another environment, state, or country?
Relies on currently quantifiable data for carbon emissions from harvesting each specific type of biomass for biofuel. The LCFS *has to* do this to come up with the specific CI numbers it uses to incrementally reduce transportation fuels CI now	Realize that some serious risks need to be avoided before they become realities which can be fully quantified, find out which biofuels pose such risks, and avoid taking those serious risks
This report does not assess the performance of the LCFS for its intended purpose — that is beyond the report scope. *This report should not be interpreted as a criticism or endorsement of the LCFS.*	**HEFA biofuel** risks that the LCFS is not designed to address are assessed in this report. *There are other ways to address these HEFA risks.*

Electrolysis is not the only proven hydrogen production technology considered in state climate pathways; however, it is the one that can store solar and wind energy, and electrolysis hydrogen can decarbonize hard-to-electrify emission sources without relying on CDR.

Renewable-powered electrolysis for zero-emission transportation

Renewable-powered electrolysis hydrogen could be critical for zero-emission transportation. Hydrogen fuel shares shown in Chart 2 represent fuel cell-electric vehicle (FCEV) fueling. Fuel cells in FCEVs convert the hydrogen back into electricity that powers their electric motors. Thus, hydrogen stored in its fuel tank is the “battery” for this type of electric vehicle. FCEVs can decarbonize transportation uses of energy where battery-electric vehicles (BEVs) might be more costly, such as long-haul freight and shipping, in which the size and mass of BEV batteries needed to haul large loads long distances reduce the load-hauling capacity of BEVs.

This zero-emission electrolysis hydrogen also plays a key role because it fuels FCEVs without relying on CDR. These zero-emission FCEVs appear crucial to the feasibility of the state climate goal for a 100% ZEV medium- and heavy-duty fleet by 2045.[78] This raises a turnkey issue because—as the difference in hydrogen fuel share between the High-CDR and the Balanced pathways in Chart 2 reflects—both electrolysis and FCEVs are proven technologies, but they nevertheless face significant infrastructure deployment challenges.[54–61]

In state climate pathways, renewable hydrogen use in transportation grows from an average of 1.24 million standard cubic feet per day (MMSCFD) in 2019[83] to roughly 1,020–1,080 MMSCFD by 2045.[56–58] This 2045 range reflects different scenarios for the mix of BEVs and FCEVs in different vehicle classes. The low end excludes FCEV use in LDVs[58] while the high end is a "central scenario" that includes both BEV and FCEV use in all vehicle classes.[57]

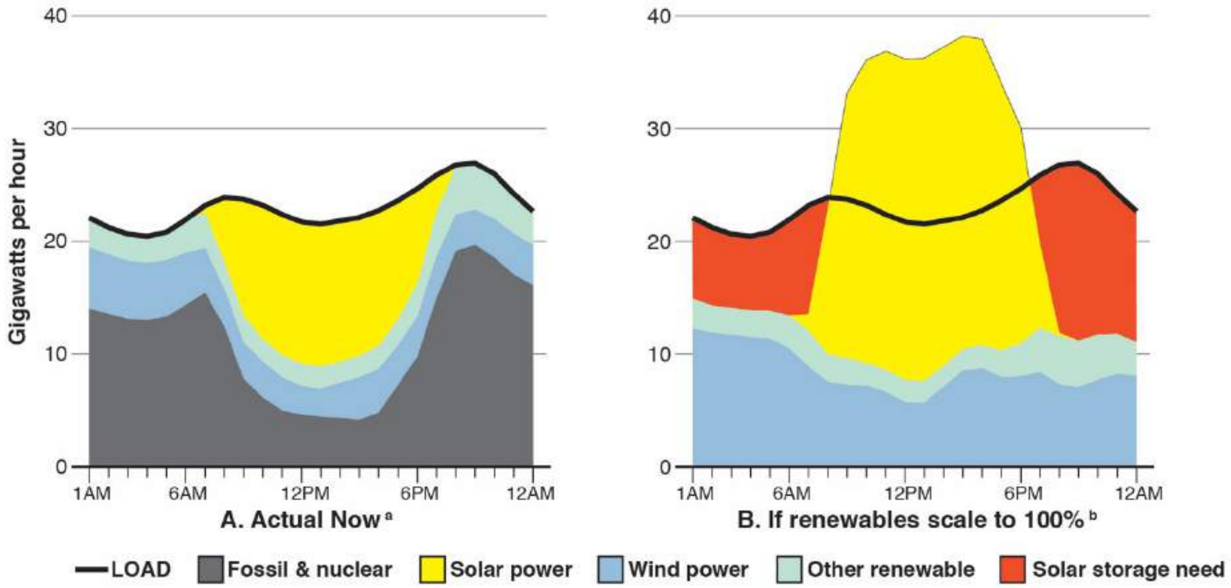
Renewable-powered electrolysis for future solar and wind power growth

Hydrogen produced by electrolysis can store solar and wind power energy, which supports the renewable energy growth needed to produce more zero-emission FCEV fuel by electrolysis. Electrolysis hydrogen plays a key role in the further growth of solar and wind energy resources, because it can store that energy efficiently for use overnight as well as over longer windless periods. The direct use of electricity for energy—in grid jargon, the "load"—occurs in the same instant that electricity is generated. This is a challenge for climate pathways because solar and wind power are intermittent electricity generators, while electricity use (load) is continuous, and varies differently from solar and wind power generation over time.

Substantial energy storage will be critical to a renewable electricity grid. There are other storage technologies such as ion batteries, compressed air, hydropower management and power-to-gas turbines, and climate pathways include multiple measures to balance renewable grids.[54–61] However, electrolysis hydrogen is particularly beneficial because it can provide efficient long-term storage over wind cycles as well as short-term storage over solar cycles while fueling ZEV growth. Charts 3 A and B below illustrate the scale of the solar energy storage need.

Load, the thick black curve that does not change from Chart A to Chart B, shows how much electric power we need and when we need it. In the renewables scale-up scenario (B), the yellow above the load curve is peak solar generation that could be wasted ("curtailed") if it cannot be stored, and the red below the load curve indicates "blackouts" we could avoid by storage of the otherwise wasted energy for use when it gets dark. This is only an example on one hypothetical day, but to continue the illustration, the energy that storage could shift, from yellow above the load curve to red below it, compares to the energy stored in ~1,500 MMSCF of hydrogen.

State climate pathways assign electrolysis a key role in meeting part of this enormous grid-balancing need. Energy storage would be accomplished by a mix of technologies and measures, including renewable-powered electrolysis hydrogen and others.[54–58] Increasing needs for energy storage in climate pathways become substantial before 2030, and the role of electrolysis hydrogen in this storage grows by up to approximately 420 MMSCFD by 2045.[58]



3. California electricity load shape on 20 April: Actual in 2021 *v.* renewable power.

A high-renewables future will require short-term storage of peak solar power generation for use at night. *See* yellow above and red below the black line showing total electricity load that can be used at the time power is generated, in this example. Solar electrolysis hydrogen stored in the fuel tanks of zero-emission trucks could be a needed part of the solution. **a.** Data reported for 20 April 2021.[84] **b.** Example scenario scales up solar and wind data proportionately to replace total fossil and nuclear generation on this day.

Renewable-powered electrolysis hydrogen for least-cost energy integration measures

Climate pathway analyses underscore both the challenge and the benefits of integrating electrolysis hydrogen across the transportation and electricity sectors. The scale-up challenge appears urgent. From ~2.71 MMSCFD by the end of 2021,[58] in-state electrolysis capacity would reach ~1,440–1,500 MMSCFD by 2045 to meet all of the transportation and energy storage needs for hydrogen discussed above.[56–58] Ramping to that scale, however, achieves economies of scale in electrolysis hydrogen production and fueling that overcome significant deployment barriers to growth of this zero-emission FCEV fuel; electrolysis hydrogen costs can be expected to fall from above to below those of steam reforming hydrogen around 2025–2035.[55, 56, 58, 84, 85] Policy intervention to meet critical needs for earlier deployment is assumed to drive ramp-up.[58]

Then, once deployed at scale, integration of electrolysis, transportation and the electricity grid can provide multiple systemic benefits. It can cut fuel costs by enabling FCEVs that are more efficient than diesel or biofuel combustion vehicles,[86] cut health costs by enabling zero-emission FCEVs,[57, 87] cut energy costs by using otherwise wasted peak solar and wind power,[58, 85] and enable priority measures needed to decarbonize hard-to-electrify energy emissions.[54, 55, 57, 58, 85] From the perspective of achieving lower-risk climate stabilization pathways, renewable-powered electrolysis hydrogen may be viewed as a stay-in-business investment.

State climate pathway benchmarks for hydrogen energy storage, transportation fuel, and refining that HEFA biofuel growth could affect

Electrolysis hydrogen production in state pathways could reach ~ 420 MMSCFD for energy storage and approximately 1,020–1,080 MMSCFD for transportation, as noted above, and could grow due to a third need and opportunity, which also could be affected by HEFA biofuel growth. The Hydrogen Roadmap in state climate pathways includes converting petroleum refining to renewable hydrogen production,[58] an enormously consequential measure, given that current hydrogen capacity committed to crude refining statewide totals ~1,216 MMSCFD.[88]

4.1.4 Replacement of gasoline with BEVs would idle crude refining capacity for distillates as well, accelerating growth of a petroleum diesel replacement fuels market that ZEVs, biofuels, or both could capture

BEVs could replace gasoline quickly

Gasoline combustion inefficiencies make battery electric vehicle (BEV) replacement of gasoline a cost-saving climate pathway measure. By 2015 BEVs may already have had lower total ownership cost than gasoline passenger vehicles in California.[89] BEVs go three times as far per unit energy as same-size vehicles burning gasoline,[90] have fewer moving parts to wear and fix—for example, no BEV transmissions—have a fast-expanding range, and a mostly-ready fuel delivery grid. Economics alone should make gasoline obsolete as fast as old cars and trucks wear out, strongly supporting the feasibility of state goals for BEVs and other zero-emission vehicles (ZEVs) to comprise 100% of light-duty vehicle (LDV) sales by 2035.[78] State climate pathways show that BEVs can be 30–100% of LDV sales by 2030–2035, 60–100% of LDV and medium-duty vehicle sales by 2030–2045, and comprise most of the California vehicle fleet by 2045.[55] [57] Electricity-powered LDVs and MDVs would thus replace gasoline relatively quickly.

Gasoline replacement would idle petroleum distillates production

Crude refining limitations force petroleum distillate production cuts as gasoline is replaced. Existing California refineries cannot make distillates (diesel and jet fuel) without coproducing gasoline. From 2010–2019 their statewide distillates-to-gasoline production volumes ratio was 0.601 and varied annually from only 0.550 to 0.637.[91] This reflects hard limits on refining technology: crude distillation yields a gasoline hydrocarbon fraction, and refineries are designed and built to convert other distillation fractions to gasoline, not to convert gasoline to distillates. During October–December in 2010–2019, when refinery gasoline production was often down for maintenance while distillate demand remained high, the median distillate-to-gasoline ratio rose only to 0.615.[1] That is a conservative estimate for future conditions, as refiners keep crude rates high by short-term storage of light distillation yield for gasoline production after equipment is returned to service.[1] [91] When gasoline and jet fuel demand fell over 12 months following the 19 March 2020 COVID-19 lockdown[36] the ratio fell to 0.515.[91] Future permanent loss of gasoline markets could cut petroleum distillate production to less than 0.615 gallons per gallon gasoline. Climate pathways thus replace petroleum distillates along with gasoline.

Existing distillates distribution infrastructure favors biofuels, emphasizing the need for early deployment of FCEVs and zero-emission electrolysis hydrogen

Fuel cell-electric vehicle (FCEV) transportation faces a challenge in the fact that existing petroleum distillates distribution infrastructure can be repurposed to deliver drop-in biofuels to truck, ship, and jet fuel tanks, while hydrogen fuel infrastructure for FCEVs must ramp up. Hydrogen-fueled FCEV growth thus faces deployment challenges which biofuels do not.[54–61] Those infrastructure challenges underly the urgent needs for early deployment of FCEVs and electrolysis hydrogen identified in state climate pathway analyses.[54–58] Indeed, early deployment is an underlying component of the climate pathway benchmarks identified above.

4.2 HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes, interfere with achieving electrolysis hydrogen energy integration benchmarks, and exceed the state climate target for emissions in 2050

4.2.1 HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes

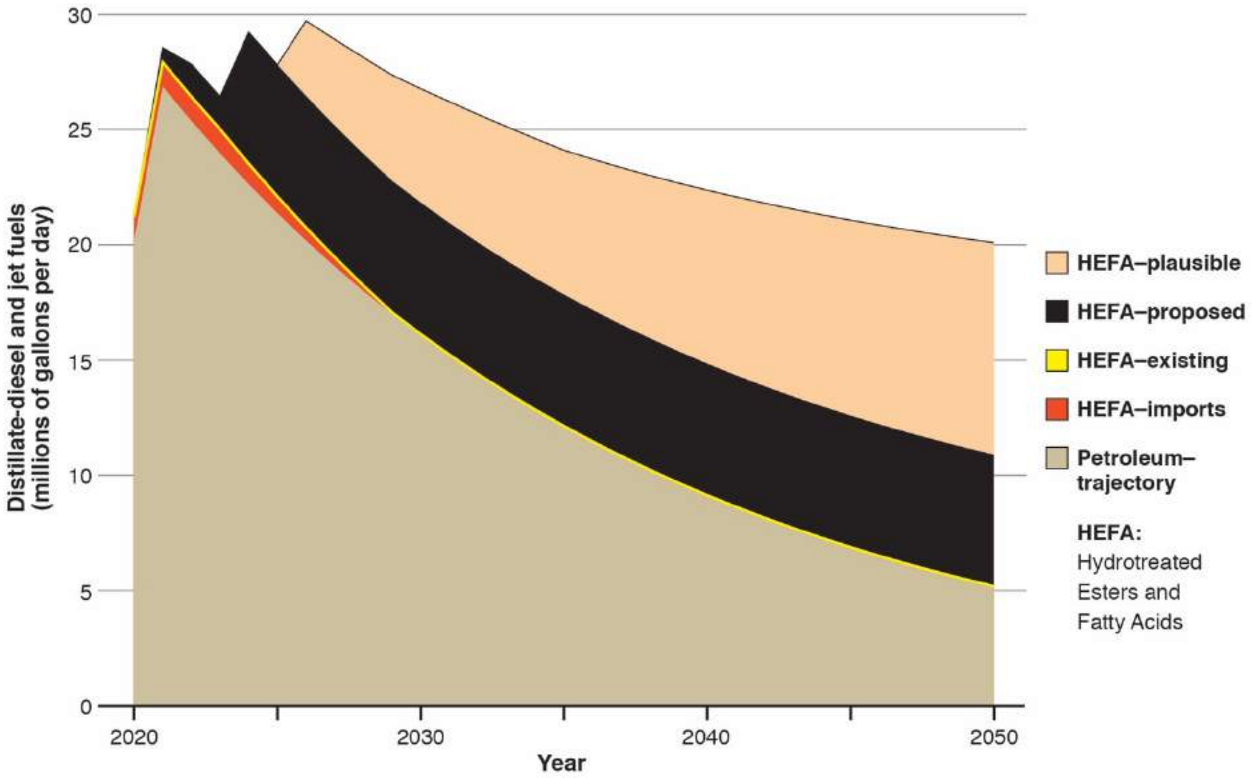
Proposed projects would exceed HEFA biofuel caps

Current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by P66, MPC, AltAir and GCE for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.[1–6] If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0–1.5 billion gal./y in state climate pathways (§4.1.2).

Continued repurposing of idled crude refining assets for HEFA biofuels could exceed the total liquid combustion fuels volume benchmarks in state climate pathways

Further HEFA biofuels growth, driven by incentives for refiners to repurpose soon-to-be-stranded crude refining assets before FCEVs can be deployed at scale, could exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up (§ 4.1.4), and refiners would be highly incentivized to protect those otherwise stranded assets (Chapter 1).

Chart 4 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 4.



4. Combustion fuels additive potential of HEFA diesel and jet production in California.

As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillate-diesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lower-carbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs.

Petroleum-trajectory for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J:G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020–2021 reflect the expected partial rebound from COVID-19.

HEFA-imports and **HEFA-existing** are the mean D+J “renewable” volumes imported, and refined in the state, respectively, from 2017–2019. The potential in-state expansion shown could squeeze out imports.

HEFA-proposed is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively.

HEFA-plausible: as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways,[55] and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market[92] anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H_2 demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J : D product slate ratio growing from 1 : 5.3 to 1 : 2, during 2025–2035.

For data and methodological details see Table A7.[1]

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.[1.] HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6–3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.[55] This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market—a fuel share which HEFA refiners would then be motivated to retain.

This climate impact of HEFA biofuels growth is reasonably foreseeable

The scenario shown in Chart 4 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.[92] HEFA growth by 2025 in the Chart 4 scenario is less than half of those plans. State climate pathways reported by Mahone et al.[55] replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 4, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets—and there are additional reasons why HEFA biofuel could become locked-in, as discussed below.

4.2.2 Continued use of steam reforming for refinery hydrogen could interfere with meeting state climate pathway benchmarks for electrolysis hydrogen energy integration, and lock HEFA biofuels in place instead of supporting transitions to zero-emission fuels

In contradiction to the conversion of refineries to renewable hydrogen in state climate pathways (§4.1.3), refiners propose to repurpose their high-carbon steam reforming hydrogen production assets for HEFA biofuels refining (chapters 1, 3). This would foreclose the use of that hydrogen for early deployment of ZEVs and renewable energy storage, the use of those sites for potentially least-cost FCEV fueling and renewable grid-balancing, and the future use of that hydrogen by HEFA refiners in a pivot to zero emission fuels. These potential impacts, together with HEFA refiner motivations to retain market share (§ 4.2.1), could result in HEFA diesel becoming a locked-in rather than a transitional fuel.

Repurposing refinery steam reforming for HEFA would circumvent a renewable hydrogen benchmark and interfere with early deployment for FCEVs and energy storage, slowing growth in ZEV hydrogen fuel and renewable energy for ZEV fuels production

Repurposing refinery steam reforming for HEFA fuels, as refiners propose,[2–6] instead of switching crude refining to renewable hydrogen, as the hydrogen roadmap in state climate pathways envisions,[58] could foreclose a very significant deployment potential for zero-emission fuels. Nearly all hydrogen production in California now is steam reforming hydrogen committed to oil refining.[56] Statewide, crude refinery hydrogen capacity totals ~1,216 MMSCFD,[88] some 980 times renewable hydrogen use for transportation in 2019 (1.24 SCFD)[83] and ~450 times planned 2021 electrolysis hydrogen capacity (~2.71 MMSCFD).[58] Repurposing crude refining hydrogen production for HEFA refining would perpetuate the commitment of this hydrogen to liquid combustion fuels instead of other potential uses. Importantly, that hydrogen would not be available for early deployment of FCEVs in the hard-to-electrify long haul freight and shipping sectors, or energy storage grid-balancing that will be needed for solar and wind power growth to fuel both zero emission FCEVs and BEVs.

By blocking the conversion of idled refinery hydrogen capacity to renewable hydrogen, repurposing idled crude refinery steam reforming for HEFA biofuels could slow ZEV fuels growth. Chart 5 below illustrates the scale of several potential impacts. Hydrogen demand for HEFA biofuels could exceed that for early deployment of FCEVs (Chart, 2025), exceed hydrogen demand for energy storage grid-balancing (Chart, 2045), and rival FCEV fuel demand for hydrogen in climate pathways through mid-century (*Id.*). ZEV growth could be slowed by foreclosing significant potential for zero-carbon hydrogen and electricity to produce it.

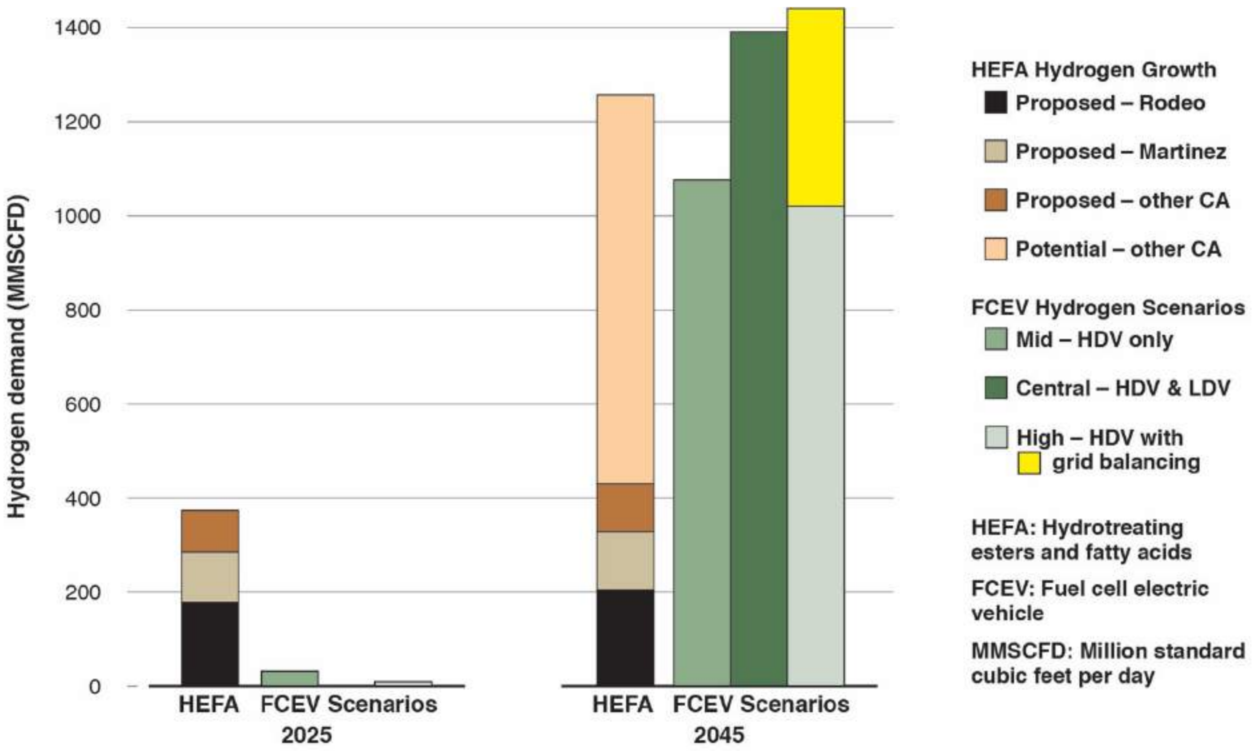
Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

Repurposing idled crude refinery steam reforming for HEFA biofuel production would foreclose reuse of otherwise idled refinery sites for renewable-powered electrolysis hydrogen. This site foreclosure impact could be important because of the potential electrolysis sites availability and location. Proximity to end-use is among the most important factors in the feasibility of renewable hydrogen build-out,[58] and refineries are near major California freight and shipping corridors and ports, where dense land uses make the otherwise idled sites especially useful for electrolysis siting. Repurposing crude refineries for HEFA biofuels could thus slow the rapid expansion of renewable-powered electrolysis hydrogen needed in climate pathways.

Continued use of steam reforming would lock HEFA refiners out of future ZEV fueling, further contributing to HEFA combustion fuels lock-in

Committing HEFA refineries to carbon-intensive steam reforming hydrogen would lock the refiners, who then would not be able to pivot toward future fueling of zero-emission FCEVs, into continued biofuel production. HEFA refiners would thus compete with hydrogen-fueled FCEVs in the new markets for fuels to replace petroleum diesel. In this HEFA growth scenario, the hydrogen lock-in, electrolysis site lockout, and ZEV fuel impacts described directly above could be expected to reinforce their entrenched position in those markets. This would have the effect of locking refiners into biofuels instead of ZEV fuels, thereby locking-in continued biofuel use at the expense of a transition to zero-emission fuels.

Crucially, multiple state pathway scenario analyses[54–56 58] show that the simultaneous scale-up of FCEVs in hard-to-electrify sectors, renewable-powered electrolysis for their zero-emission fuel, and solar and wind power electricity to produce that hydrogen, already faces substantial challenges—apart from this competition with entrenched HEFA biofuel refiners.



5. Potential growth in hydrogen demand for HEFA biorefineries, fuel cell electric vehicle (FCEV) goods movement, and renewable electricity grid balancing to 2025 and 2045.

HEFA biorefineries could slow the growth of zero-emission goods movement, and of renewable electricity, by committing limited hydrogen supplies to drop-in diesel before the cleaner technologies ramp up (chart, 2025), by rivaling their demand for large new hydrogen supplies through mid-century (chart, 2045), and by committing to the wrong type of hydrogen production technology. H_2 supplied by electrolysis of water with renewable electricity could fuel FCEVs to decarbonize long-haul goods movement, and could store peak solar and wind energy to balance the electricity grid, enabling further growth in those intermittent energy resources. However, nearly all California H_2 production is committed to oil refining as of 2021. Refiners produce this H_2 by carbon-intensive steam reforming, and propose to repurpose that fossil fuel H_2 technology, which could not pivot to zero-emission FCEVs or grid balancing, in their crude-to-biofuel refinery conversions.

HEFA proposed based on H_2 demand estimated for P66 Rodeo, MPC Martinez, and other California HEFA projects proposed or in construction as of May 2021. H_2 demand increases from 2025–2045 as HEFA feedstock, jet fuel, and H_2/b demands increase. For data and methods details *see* Table A7.[1]

HEFA potential based on H_2 production capacity at California petroleum refineries, additional to that for currently proposed projects, which could be idled and repurposed for potential HEFA projects along the trajectory shown in Chart 4. *See* Table A7 for data and details of methods.[1]

FCEV Mid – HDV only from Mahone et al. (2020b),[56] FCEVs are ~2% and 50% of new heavy duty vehicle sales in California and other U.S. western states by 2025 and 2045, respectively.[56]

Central – HDV & LDV from Austin et al. (2021), H_2 for California transportation, central scenario, LC1.[57]

High – HDV with grid balancing from Reed et al. (2020), showing here two components of total demand from their high case in California: non-LDV H_2 demand in ca. 2025 and 2045, and H_2 demand for storage and firm load that will be needed to balance the electricity grid as solar and wind power grow, ca. 2045.[58]

4.2.3 Potential carbon emissions could exceed the 2050 climate target

CO_2e emissions from the HEFA growth scenario were estimated based on LCFS carbon intensity values[86] weighted by the HEFA fuels mix in this scenario,[1] accounting for emission shifting effects described in Chapter 2. Accounting for this emission shift that would be caused by replacing petroleum with excess HEFA biofuel use in California at the expense of abilities to do so elsewhere—excluding any added land use impact—is consistent with the LCFS and state climate policy regarding emission "leakage."[62] Results show that HEFA diesel and jet fuel CO_2e emissions in this scenario could reach 66.9 million tons (Mt) per year in 2050. *See* Table 5.

Table 5. Potential CO_2e emissions in 2050 from HEFA distillates refined and used in California.

Distillates volume		
HEFA distillates refined and burned in CA [a]	5.47	billion gallons per year
CA per capita share of lipid-based biofuel [b]	0.58	billion gallons per year
Excess lipids shifted to CA for HEFA biofuel [c]	4.89	billion gallons per year
Distillate fuels mix		
HEFA diesel refined and burned in CA [d]	66.7	percentage of distillates
HEFA jet fuel refined and burned in CA [d]	33.3	percentage of distillates
Fuel chain carbon intensity		
HEFA diesel carbon intensity [e]	7.62	kg CO_2e/gallon
HEFA jet fuel carbon intensity [e]	8.06	kg CO_2e/gallon
Petroleum diesel carbon intensity [e]	13.50	kg CO_2e/gallon
Petroleum jet fuel carbon intensity [e]	11.29	kg CO_2e/gallon
Emissions (millions of metric tons as CO_2e)		
From CA use of per capita share of lipids	4.50	millions of metric tons per year
From excess CA HEFA use shifted to CA	37.98	millions of metric tons per year
Emissions shift to other states and nations [f]	24.44	millions of metric tons per year
Total HEFA distillate emissions	66.92	millions of metric tons per year

a. Potential 2050 HEFA distillates refinery production and use in California in the scenario shown in Chart 4.[1]
b. Statewide per capita share of U.S. farm yield for all uses of lipids used in part for biofuels, from data in Table 1, converted to distillates volume based on a feed specific gravity of 0.914 and a 0.809 feed-to-distillate fuel conversion efficiency. Importantly, these purpose-grown lipids have other existing uses (Chapter 2).
c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used elsewhere to replace petroleum with HEFA biofuels. Per capita share of total U.S. production for all uses, rather than that share of lipids available for biofuel, represents a conservative assumption in this estimate.
d. Distillate fuels mix in 2050 (1 gallon jet fuel to 3 gallons diesel) as described in Table A7 part f.[1]
e. Carbon intensity (CI) values from tables 3, 7-1, and 8 of the California LCFS Regulation.[86] HEFA values used (shown) were derived by apportioning "fats/oils/grease residues" and "any feedstocks derived from plant oils" at 31% and 69%, respectively, based on the data in Table 1.
f. Future emissions that would not occur if other states and nations had access to the lipid feedstock committed to California biofuel refining and combustion in excess of the state per capita share shown. Shifted emissions based on the difference between HEFA and petroleum CI values for each fuel, applied to its fuels mix percent of excess lipid-based distillates shifted to CA for HEFA biofuel. Accounting for emissions caused by replacing petroleum in CA *instead of* elsewhere, separately from any added land use impact, is consistent with the LCFS and state climate policy regarding "leakage."[62] Total emissions thus include shifted emissions.

Emissions from the remaining petroleum distillate fuels in this scenario, ~5,113,000 gal./d or 1.87 billion gal./y (Chart 4; Table A7[1]), would add 22.1–24.2 Mt/y, if diesel is 25–75% of the 2050 petroleum distillates mix, at the petroleum carbon intensities in Table 5. Thus, distillate transportation fuel emissions alone (89–91 Mt/y) could exceed the 86.2 Mt/y 2050 state target for CO_2e emissions from all activities statewide.[77] Total 2050 emissions would be larger unless zeroed out in all other activities statewide. Repurposing idled petroleum refinery assets for HEFA biofuels threatens state climate goals.

4.3 A zero-emission electrolysis hydrogen alternative can be deployed during a crucial window for breaking carbon lock-in: HEFA biofuels growth could impact the timing, and thus the emission prevention, clean fuels development, and transition benefits, of this zero-emission electrolysis hydrogen alternative.

Potential benefits to climate pathways from converting hydrogen production to renewable-powered electrolysis (electrolysis) at refinery sites were assessed with and without HEFA biofuels expansion. The "HEFA Case" captures proposed and potential HEFA growth; the "No HEFA Case" is consistent state climate pathways that exclude purpose-grown lipids-derived biofuels in favor of cellulosic residue-derived biofuels.[54] [55] Conversion to electrolysis is assumed to occur at crude refineries in both cases, consistent with the hydrogen road map in state climate pathways,[58] but as an early deployment measure—assumed to occur during 2021–2026. This measure could reduce refinery carbon intensity, increase zero-emission transportation and electricity growth, and reduce local transition impacts significantly, and would be more effective if coupled with a cap on HEFA biofuels.

4.3.1 Electrolysis would prevent HEFA biofuels from increasing the carbon intensity of hydrocarbon fuels refining

Deployment timing emerges as the crucial issue in this analysis. "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."[70] The design phase for HEFA refinery conversions, and petroleum refinery turnarounds that occur on 3- to 5-year cycles are critical insertion points for electrolysis in place of carbon-intensive steam reforming. This zero-emission measure would cut the carbon intensity of refining at any time, however, climate stabilization benefit is directly related to the cumulative emission cut achieved, so the effectiveness of this measure would also depend upon how quickly it would be deployed.

Refining CI benefits in the HEFA Case

Replacing steam reforming with electrolysis could cut the carbon intensity (CI) of HEFA refining by ~72–79%, from ~76–101 kg/b to ~21 kg/b refinery feed (Chapter 3). This would cut the CI of HEFA fuels processing from significantly above that of the average U.S. petroleum refinery (~50 kg/b crude; *Id.*) to significantly below the CI of the average U.S. crude refinery.

Refining CI benefits in the No HEFA Case

Replacing steam reforming with electrolysis at petroleum refineries would reduce CI by ~34% based on San Francisco Bay Area data,[66] however, in other states or nations where refiners run less carbon-intensive crude and product slates than in California, this ~34% may not apply.[64]

Refining CI reduction effectiveness

Cumulative emission cuts from hydrogen production would be the same in both cases since hydrogen emissions would be eliminated from HEFA refineries in both cases. Based on the CI values above and the HEFA growth trajectory[1] in Chart 4 this measure could prevent ~194–282 million tons (Mt) of CO_2 emission from HEFA hydrogen production through 2050. Petroleum refinery emissions could be cut by 103 Mt through 2050, based on the median mixed feed CI of steam reforming (24.9 g/SCF, Table 3) and the remaining refinery hydrogen production underlying the distillates trajectory in Chart 4 from 2026–2050.[1] Total direct *cumulative* emissions prevented could be ~297–400 Mt. *Annual* fuel chain emissions from all distillates in transportation in 2050 (89–91 Mt/y) could be cut by ~12–16%, to ~76–78 Mt/y in the HEFA Case. In the No HEFA Case annual fuel chain emissions from petroleum distillates in 2050 (~22–24 Mt/y) could be cut by ~8–9%, to ~20–22 Mt/y, although use of other biofuels along with ZEVs could add to that 20–22 Mt/y significantly. This measure would be effective in all cases, and far more effective in climate pathways that cap HEFA growth and transition to ZEVs.

4.3.2 Use of electrolysis would facilitate development of hydrogen for potential future use in transportation and energy storage

Deployment timing again is crucial. Electrolysis can integrate energy transformation measures across transportation and electricity, speeding both FCEV growth and renewable power growth (§ 4.1). Benefits of this energy integration measure could coincide with a window of opportunity to break free from carbon lock-in, which opened with the beginning of petroleum asset stranding shown in Chapter 1 and could close if refiner attempts to repurpose those assets entrench a new source of carbon in the combustion fuel chain. As Seto et al. conclude:

> "Understanding how and when lock-in emerges also helps identify windows of opportunity when transitions to alternative technologies and paths are possible [.] ... either in emergent realms and sectors where no technology or development path has yet become dominant and locked-in or at moments when locked-in realms and sectors are disrupted by technological, economic, political, or social changes that reduce the costs of transition ... ."[93]

Here, in a moment when the locked-in petroleum sector has been disrupted, and neither FCEV nor HEFA technology has yet become dominant and locked into the emergent petroleum diesel fuel replacement sector, this electrolysis energy integration measure could reduce the costs of transition if deployed at scale (§ 4.1). Indeed, state climate pathway analyses suggest that the need for simultaneous early deployment of electrolysis hydrogen, FCEVs, and energy storage load-balancing—and the challenge of scaling it up in time—are hard to overstate (§§ 4.1, 4.2).

Clean fuels development benefits in the HEFA Case

Converting refinery steam reforming to electrolysis during crude-to-biofuel repurposing before 2026 and at refineries to be idled and repurposed thereafter could provide electrolysis hydrogen capacities in 2025 and 2045 equivalent to the HEFA steam reforming capacities shown in Chart 5. However, HEFA refining would use this hydrogen, foreclosing its use to support early deployment of FCEVs and energy storage, and could further commit the share of future transportation illustrated in Chart 4 to liquid combustion fuel chain infrastructure.

Planned policy interventions could deploy electrolysis[58] and FCEVs[78] separately from refinery electrolysis conversions, although less rapidly without early deployment of this measure. If separate early deployment is realized at scale, this measure would enable HEFA refiners to pivot toward FCEV fueling and energy storage later. However, refinery combustion fuel share lock-in (§4.2) and competition with the separately developed clean hydrogen fueling could make that biofuel-to-ZEV-fuel transition unlikely, absent new policy intervention.

Clean fuels development benefits in the No HEFA Case

In the No HEFA Case, cellulosic residue-derived instead of HEFA biofuels would be in climate pathways,[55] and crude refinery steam reforming would be converted to electrolysis when it is idled before 2026 and in turnarounds by 2026. Instead of committing converted electrolysis hydrogen to HEFA refining as crude refining capacity is idled, it would be available for FCEVs and energy storage in the same amounts shown in Chart 5. This could fuel greater early FCEV deployment than state climate pathways assume (Chart, 2025), provide more hydrogen energy storage than in the pathways (Chart, 2045), and fuel most of the FCEV growth in the pathways through 2045 (*Id.*). These estimates from Chart 5 are based on the petroleum decline trajectory[1] underlying Chart 4, which is supported by economic drivers as well as climate constraints (§ 4.1) and assumes slower petroleum replacement through 2045 than state climate pathways (§ 4.2).

Clean fuels development benefits effectiveness

Energy integration benefits of this measure could be highly effective in supporting early deployment of zero-emission transportation during a crucial window of opportunity for replacing liquid hydrocarbon combustion fuels, and could fuel hydrogen storage as well as most zero-emission FCEV growth needs thereafter, in the No HEFA Case. In the HEFA Case, however, those benefits could be limited to an uncertain post-2030 future. These results further underscore the importance of limiting HEFA biofuel growth in state climate pathways.

4.3.3 Use of electrolysis could lessen transition impacts from future decommissioning of converted refineries

Just transitions, tailored to community-specific needs and technology-specific challenges, appear essential to the feasibility of climate stabilization.[66 94] Full just transitions analysis for communities that host refineries is beyond the scope of this report, and is reviewed in more detail elsewhere.[66 94] However, the recent idling of refining capacity, and proposals to repurpose it for HEFA biofuels, raise new transition opportunities and challenges for California communities which were identified in this analysis, affect the feasibility of climate pathways, and thus are reported here. Hydrogen plays a pivotal role in the new transition challenges and opportunities which communities that host California refineries now face.

Transition benefits in the HEFA Case

Electrolysis would enable HEFA refineries to pivot from using hydrogen for biofuel to selling it for FCEV fuel, energy storage, or both. Assuming state climate pathways that replace transportation biofuels with ZEVs[57] achieve the state goal for 100% ZEV medium- and heavy-duty vehicles by 2045,[78] this would allow HEFA refiners to transition from HEFA biofuel hydro-conversion processing while continuing uninterrupted hydrogen production at the same sites. Potential benefits would include reduced local job and tax base losses as compared with total facility closure, and eliminating the significant refinery explosion/fire risk and local air pollution impacts from HEFA hydro-conversion processing that are described in Chapter 3.

However, HEFA lock-in could occur before the prospect of such a biofuel-to-ZEV fuel transition could arise (§ 4.2). Conversions to electrolysis would lessen incentives for refiners to protect assets by resisting transition, and yet their fuel shares in emerging petroleum distillates replacement markets and incentives to protect those market shares would have grown (*Id.*).

Transition benefits in the No HEFA Case

In the No HEFA Case electrolysis hydrogen could pivot to FCEV fueling, energy storage, or both as petroleum refining capacity is idled in state climate pathways. Petroleum asset idling would be driven by economic factors that replace gasoline as well as climate constraints and thus be likely to occur (§ 4.1). Indeed, it has begun to occur (Chapter 1) and is likely to gather pace quickly (§§ 4.1, 4.2). Local job and tax base retention resulting from this hydrogen pivot in the No HEFA Case could be of equal scale as in the HEFA case. Local benefits from elimination of refinery hazard and air pollution impacts upon site transition would be from replacing petroleum refining rather than HEFA refining and would be realized upon crude refinery decommissioning rather than upon repurposed HEFA refinery decommissioning years or decades later.

Transition benefits effectiveness

Electrolysis hydrogen could have a pivotal role in just transitions for communities that host refineries. However, transition benefits of electrolysis would more likely be realized, and would be realized more quickly, in the No HEFA Case than in the HEFA Case. Realization of these potential transition benefits would be uncertain in the HEFA Case, and would be delayed as compared with the No HEFA Case.

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APPENDIX B

Karras, G., *Unsustainable Aviation Fuel*
(Karras, 2021b)

UNSUSTAINABLE AVIATION FUEL

An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel in repurposed crude refineries

A Natural Resources Defense Council (NRDC) Report

Prepared for the NRDC by Greg Karras, G. Karras Consulting
www.energy-re-source.com

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CONTENTS

Executive Summary

Current climate, energy and aviation policy use the term Sustainable Aviation Fuel (SAF) to mean alternatives to petroleum aviation fuel which could include seven types of biofuels and can replace up to half of petroleum jet fuel under existing aviation fuel blending limits. In practice this definition of SAF favors continued use of existing combustion fuel infrastructure to burn a mix of biofuel and petroleum. That is not a net-zero carbon climate solution in itself, and in this sense, SAF is not sustainable. Rather, the partial replacement of petroleum jet fuel with biofuel is meant to incrementally reduce emissions from the hard-to-decarbonize aviation sector and, in concert with more effective measures in other sectors, help to achieve climate stabilization goals.

A question, then, is whether the type of biofuel favored by the existing combustion fuel infrastructure will, in fact, emit less carbon than petroleum. This, the evidence suggests, is a key question for the sustainability of SAF.

Although it is but one proven technology for the production of SAF, Hydrotreated Esters and Fatty Acids (HEFA) technology is the fastest-growing type of biofuel in the U.S. today. This rapid recent and projected growth is being driven by more than renewable fuels incentives. The crucially unique and powerful driver of HEFA biofuel growth is that oil companies can protect troubled and climate-stranded assets by repurposing petroleum crude refinery hydro-conversion and hydrogen plants for HEFA jet fuel and diesel biofuels production.

Some HEFA biofuels are reported to emit more carbon per gallon than petroleum fuels. This is in part because HEFA technology depends upon and competes for limited agricultural or fishery yields of certain types—oil crops, livestock fats or fish oils—for its biomass feedstocks. Meeting increased demands for at least some of those feedstocks has degraded natural carbon sinks, causing indirect carbon emissions associated with those biofuels. And it is in part because HEFA feedstocks require substantial hydrogen inputs for HEFA processing, resulting in very substantial direct carbon emissions from fossil fuel hydrogen production repurposed for HEFA biorefining. Both processing strategies, i.e., refining configurations to target jet fuel *v.* diesel production, and feedstock choices, e.g., choosing to process palm oil *v.* livestock fat feeds, are known factors in these direct and indirect emissions. That is important because HEFA jet fuel yield is limited, and refiners can use various combinations of feeds and processing strategies to boost jet yield with repurposed crude refining equipment. To date, however, the combined effect of these factors in strategies to boost HEFA jet fuel yield has received insufficient attention.

This report focuses on two questions about climate impacts associated with HEFA jet fuel production in repurposed crude refineries. First, could feedstocks that enable refiners to boost jet fuel yield increase the carbon dioxide emission per barrel—the carbon intensity—of HEFA refining relative to the feeds and processing strategy refiners use to target HEFA diesel yield? Second, could the acquisition of feedstocks that refiners can use to increase HEFA jet fuel yield result in comparatively more serious indirect climate impacts?

The scope of the report is limited to these two questions. Its analysis and findings are based on publicly reported data referenced herein. Data and analysis methods supporting feed-specific original research are given and sourced in an attached data and methods table.[1] Data limitations are discussed in the final chapter. This work builds on recent NRDC-sponsored research[2] which is summarized in relevant part as context above, and as referenced in following chapters.

Chapter 1 provides an overview of HEFA technology, including the essential processing steps for HEFA jet fuel production and additional options for maximizing jet fuel yield using repurposed crude refining assets. This process analysis shows that a growing fleet of HEFA refineries could, and likely would, use a combination of strategies in which the use of intentional hydrocracking (IHC) could vary widely. HEFA refiners could produce HEFA jet fuel without intentional hydrocracking (No-IHC), produce more HEFA jet fuel with IHC in the isomerization step needed for all HEFA fuels (Isom-IHC), or produce more HEFA jet fuel while shaving the increased hydrogen costs of intentional hydrocracking (Selective-IHC). The strategies chosen would be influenced by the capabilities of crude refineries repurposed for HEFA processing.

Chapter 2 reviews HEFA feedstock limitations and supply options, presents detailed data relating feedstock properties to effects on HEFA jet fuel yields and process hydrogen demand, and ranks individual feedstocks for their ability to increase HEFA jet fuel yield. Differences in chemistry among feeds result in different feed rankings for jet fuel *versus* diesel yields, different feed rankings for increased jet fuel yield among processing strategies, and different feed rankings for hydrogen demand among processing strategies. Palm oil, livestock fats, and fish oils boost jet fuel yield without intentional hydrocracking, and enable more refiners to further boost jet yield with intentional hydrocracking, which increases HEFA process hydrogen demand.

Chapter 3 describes and quantifies refining strategy-specific and feed-specific carbon dioxide (CO_2) emissions from the repurposed crude refinery steam reformers that produce hydrogen for HEFA processing. Feed-specific carbon intensity (CI) rankings for jet fuel-range feed fractions mask those for whole feed actual CI when refiners use the No-IHC process strategy. Refining CI rankings for some feeds with low *v.* high jet yields (e.g., soybean oil *v.*

menhaden fish oil) are reversed in the Selective-IHC strategy compared with the other strategies for increasing HEFA jet fuel yield. Some feeds that increase jet fuel yield have relatively higher process CI (fish oils) while others have relatively lower process CI (palm oil and livestock fats). However, palm oil and livestock fat feeds also enable the highest-CI refining strategies, and all strategies for HEFA jet fuel production result in substantially higher refining CI than the average U.S. petroleum refinery CI. This shows that HEFA jet fuel growth would increase the carbon intensity of hydrocarbon fuels processing.

Chapter 4 reviews natural carbon sinks and assesses potential carbon emission impacts from increasing production of the specific food system resources HEFA refiners can use as feedstocks. Palm oil, livestock, and fisheries production emit from these carbon sinks. Present assessments confirm this "indirect" impact of palm oil biofuels, but suggest livestock fat and fish oil biofuels have relatively low feed production emissions due to the assumption that biofuel demand will not expand livestock production or fisheries catch. Some also assume U.S. policies that discourage palm oil biofuels prevent palm oil expansion to fill in for other uses of biomass biofuels displace. Those assumptions, however, are based on historical data, when biofuels demand was far below total production for the type of biomass HEFA refiners can process. HEFA feedstock demand could far exceed total current U.S. production for all uses of that biomass type—including food and fuel—if HEFA jet fuel replaces as little as 18 percent of current U.S. jet fuel consumption.

With HEFA jet fuel growth to replace 18 percent of U.S. jet fuel, world livestock fat and fish oil production could supply only a fraction of U.S. HEFA feedstock demand unless that demand boosts their production, with consequent indirect carbon impacts. Palm oil production could expand to fill other uses for livestock fat and other plant oils which the increased U.S. biofuel demand would displace. Intensified and expanded production of soybean and other oil crops with relatively high indirect carbon impacts would likely be necessary, in addition, to supply the total demand for both food and fuel. Further, given refiner incentives to repurpose climate-stranded crude refining assets, plausible U.S. HEFA growth scenarios by mid-century range above 18 percent and up to 39 percent of U.S. jet fuel replacement with HEFA jet fuel.

Thus, data and analysis in Chapter 4 suggest the potential for significant indirect carbon emission impacts associated with the mix of HEFA jet fuel feedstocks that could meet plausible future SAF demand, and that high-jet yield feeds could contribute to or worsen these impacts.

Crucially, causal factors for these impacts would be inherent and mutually reinforcing. HEFA technology repurposed from crude refineries can process only feedstocks that are co-produced from food resources, it requires large hydrogen inputs that boost refining emissions to marginally improve its low jet fuel yield, and even then, it could require more than two tons of carbon-emitting feedstock production per ton of HEFA jet fuel produced.

Findings and takeaways from this work follow below.

Findings and Takeaways

Finding 1. Hydrotreated Esters and Fatty Acids (HEFA) biofuel technology has inherent limitations that affect its potential as a sustainable aviation fuel: low jet fuel yield on feedstock, high hydrogen demand, and limited sustainable feedstock supply.

Takeaway Climate-safe plans and policies will need to prioritize alternatives to petroleum jet fuel combustion which do not have known sustainability limitations.

Finding 2. Switching HEFA feedstocks to target increased jet fuel yield could increase the carbon intensity—CO_2 emitted per barrel feed—of HEFA refining, compared with targeting HEFA diesel yield. HEFA refining carbon intensity could increase in 80 percent of plausible feed switch and processing combinations targeting jet fuel. Direct emission impacts could be significant given that the carbon intensity of HEFA refining substantially exceeds that of U.S. petroleum refining.

Takeaway Environmental impact assessments of proposed HEFA projects will need to address potential emissions from future use of HEFA refineries to maximize jet fuel production, and assess lower emitting alternatives to repurposing existing high-carbon refinery hydrogen plants.

Finding 3. One of three feeds that could boost HEFA jet fuel yield causes carbon emissions from deforestation for palm plantations, and the other two cannot meet potential HEFA feedstock demand without risking new carbon emissions from expanded livestock production or fisheries depletion. These indirect impacts could be significant given that feedstock demand for replacing only a small fraction of current U.S. jet fuel with HEFA jet fuel would exceed total U.S. production of HEFA feedstocks biomass—biomass which now is used primarily for food.

Takeaway Before properly considering approvals of proposed HEFA projects, permitting authorities will need to assess potential limits on the use of feedstocks which could result in significant climate impacts.

Finding 4. Natural limits on total supply for the type of feedstock that HEFA technology can process appear to make replacing any significant portion of current petroleum jet fuel with this type of biofuel unsustainable.

Takeaway Sustainable aviation plans will need to consider proactive and preventive limits on HEFA jet fuel, in concert with actions to accelerate development and deployment of sustainable, climate-safe alternatives.

1. How would refiners rebuild for HEFA jet fuel production?

Oil companies can repurpose existing fossil fuel hydrogen plants, hydrocrackers, and hydrotreaters at their petroleum refineries to produce jet fuel and diesel biofuels using a technology called hydrotreating esters and fatty acids (HEFA). "Hydrotreating" means a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: the triacylglycerols and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.[1]

HEFA processing requires a sequence of steps, performed in separate hydro-conversion reactors, to deoxygenate and isomerize (restructure) the lipids feedstock, and very substantial hydrogen inputs for those process steps, in order to produce diesel and jet fuels.[2]

One problem with using HEFA technology for Sustainable Aviation Fuel (SAF) is that these hydrodeoxygenation and isomerization steps alone can convert only a fraction of its feedstock into jet fuel—as little as 0.128 pounds of jet fuel per pound of soybean oil feed.[3] Intentional hydrocracking can boost HEFA jet fuel yield to approximately 0.494 pounds per pound of feed,[3] however, that requires even more hydrogen, and can require costly additional refining capacity. This chapter describes the range of processing strategies that refiners could use to increase HEFA jet fuel yields from their repurposed crude refineries.

1.1 Step 1: Hydrodeoxygenation (HDO) of jet fuel (and diesel) hydrocarbons

HEFA processing produces diesel and jet fuels from the hydrocarbon chains of fatty acids. In all HEFA feedstocks, fatty acids are bound in triacylglycerols that contain substantial oxygen, and various numbers of carbon double bonds. To free the fatty acids and make fuels that can burn like petroleum diesel and jet fuel from them, that oxygen must be removed from the whole feed. This first essential step in HEFA processing is called hydrodeoxygenation (HDO).

HDO reaction chemistry is complex, as reviewed in more detail elsewhere,[2] and its intended reactions all consume hydrogen by forcing it into the feedstock molecules. Process reactions insert hydrogen to free fatty acids from triacylglycerols ("depropanation") and to remove oxygen by bonding it with hydrogen to form water ("deoxygenation"). And along with those reactions, still more hydrogen bonds with the carbon chains to "saturate" the carbon double bonds in them. These reactions proceed at high temperatures and pressures in the presence of a catalyst to yield the intended HDO products: deoxygenated hydrocarbon chains which can be further processed to make diesel and jet fuels.

1.2 Step 2: Isomerization of jet fuel and diesel hydrocarbons

Isomerization restructures the saturated straight-chain hydrocarbons produced by HDO, which are too waxy to burn well or safely in diesel or jet engines, by turning these straight-chain hydrocarbons into their branched-chain isomers. This is the second essential HEFA process step.

Like HDO, isomerization reactions are complex, proceed at high temperatures and pressures in the presence of a catalyst, and require substantial hydrogen inputs.[2] However, isomerization process reactions, conditions, and catalysts differ substantially from those of HDO and, instead of consuming the hydrogen input as in HDO, most of the hydrogen needed for isomerization can be recaptured and recycled.[2] These differences have so far required a separate isomerization processing step, performed in a separate process reactor, to make HEFA diesel and jet fuel.

1.3 Additional option of intentional hydrocracking (IHC)

Hydrocracking breaks ("cracks") carbon bonds by forcing hydrogen between bonded carbon atoms at high temperature and pressure. This cracks larger hydrocarbons into smaller ones. It is an unwanted side reaction in HDO and some isomerization processing since when uncontrolled, it can produce compounds too small to sell as either diesel or jet fuel. *Intentional* hydrocracking (IHC) uses specialized catalysts and process conditions different from those required by HDO to crack HDO outputs into hydrocarbons in the jet fuel range.

Thus, while HEFA refiners can make jet fuel with HDO and isomerization alone (No-IHC), they could make more jet fuel by adding IHC to their processing strategy. Adding IHC for the HDO output can boost jet fuel yield to approximately 49.4 percent of HEFA feedstock mass (49.4 wt.%).[3] This boost is important, compared with No-IHC jet fuel yield of approximately 12.8 wt.% on soybean oil,[3] the most abundant HEFA feedstock produced in the U.S.[2] However, hydrocrackers are expensive to build for refineries that do not already have them,[4] and IHC increases demand for hydrogen plant production capacity by approximately 1.3 wt.% on feed (800 cubic feet of H_2/barrel).[2 3] New capacity for additional hydrogen production is also costly to refiners that cannot repurpose existing capacity. HEFA refiners that choose the IHC option to maximize jet fuel yield might choose one processing strategy to minimize new hydrocracking capacity cost, or another processing strategy to minimize new hydrogen capacity cost.

1.3.1 IHC in isomerization process units

Hydrocracking and isomerization can be accomplished in a repurposed crude refinery hydrocracker, given the necessary retooling and catalyst for HEFA HDO output processing.[2] Thus, a crude refinery with sufficient existing hydrocracking and hydrogen capacity for the whole HEFA feed stream it plans to process could repurpose that equipment for IHC in the isomerization step of its repurposed HEFA process configuration. This "Isom-IHC" processing strategy would allow that refiner to maximize HEFA jet fuel yield without the capital expense of building a new hydrocracker. However, combining intentional hydrocracking in isomerization, which is required for all HEFA fuels, cracks the entire output from the HDO step, incurring the 800 cubic feet of hydrogen per barrel cost increment on the entire HEFA feed. If a refiner lacks the existing hydrogen capacity, Isom-IHC could entail building new hydrogen plant capacity.

1.3.2 Selective IHC in separate hydrocracking process units

HEFA refiners separate the components of their HDO and isomerization outputs to re-run portions of the feed through those processes and to sell HEFA diesel and jet fuel as separate products. That distillation, or "fractionation," capacity could be used to separate the jet fuel produced by HDO and isomerization processing from their hydrocarbons output, and feed only those hydrocarbons outside the jet fuel range to a separate intentional hydrocracking unit. This "Selective-IHC" processing strategy could increase jet fuel yield while reducing IHC hydrogen consumption, and new hydrogen plant costs, compared with those of the Isom-IHC strategy. However, it would not eliminate the hydrogen production cost of IHC, and more importantly for refiners that lack the existing hydrocracking capacity before repurposing their crude refineries, it would entail building expensive new hydrocrackers.

1.4 Three potential HEFA jet fuel processing strategies

HEFA feedstock supply limitations,[2] differences in hydrogen production and hydrocracking capacities among U.S. refineries,[5] and the differences between processing strategies described above suggest the broad outlines of a prospective future HEFA jet fuel refining fleet. Refiners that can repurpose sufficient capacity could maximize HEFA jet fuel yield using IHC strategies. The fleet-wide mix would be influenced initially by whether existing hydrocracking or hydrogen production capacity would limit total production by each refinery to be repurposed. Later, the relative costs of hydrogen production *v.* hydrocracking could affect the mix of Selective-IHC *v.* Isom-IHC in the mid-century HEFA refining fleet.

Refiners that lack sufficient capacity for IHC could repurpose for the No-IHC strategy and coproduce HEFA jet fuel along with larger volumes of HEFA diesel. Then, increasing costs of the much higher feed volume needed per gallon of HEFA jet fuel yield from the No-IHC strategy could limit this strategy to a small portion of the refining fleet by mid-century. Declining HEFA diesel demand, as electric and fuel cell vehicles replace diesel vehicles, could further drive this this limitation of the No-IHC processing strategy. However, refiners that do not use intentional hydrocracking could seek to boost HEFA jet fuel yield in another way.

2. Can refiners make more HEFA jet fuel from some feedstocks than from others?

HEFA biofuel technology is limited to a particular subset of world biomass supply for its feedstock. Despite that limitation, however, differences among these lipid feeds could affect both HEFA processing and jet fuel yield. This chapter assesses individual HEFA feedstocks for potential differences in HEFA processing and HEFA jet fuel yield.

Results reveal strong interactions between feedstock and processing configuration choices. In essential HEFA process steps, feed choices affect jet fuel yield and hydrogen demand, both of which affect options to further boost jet yield with intentional hydrocracking. Both feedstock and processing choices can increase hydrogen demand, which can affect processing to boost jet fuel yield where hydrogen supply is limited. Feed-driven and process strategy-driven impacts on hydrogen demand overlap, however, feed rankings for hydrogen differ from those for jet yield, and differ among processing configurations. From the lowest to highest impact combinations of feedstock and processing options, jet fuel yield and hydrogen demand increase dramatically.

Palm oil, livestock fat, and fish oil have relatively high jet fuel yields without intentional hydrocracking, and relatively high potentials to enable further boosting jet fuel yields with intentional hydrocracking (IHC).

2.1 HEFA feedstock limitations and supply options

HEFA biofuel technology relies on the fatty acids of triacylglycerols in biomass lipids for its feedstocks, as described in Chapter 1. Sources of these in relevant concentrations and quantities are limited to farmed or fished food system lipids resources. Among its other problems, which are addressed in a subsequent chapter, this technological inflexibility limits feedstock choices for refiners seeking to increase HEFA jet fuel yield.

Historically used lipid biofuel feedstock supplies include palm oil, soybean oil, distillers corn oil, canola (rapeseed) oil, and cottonseed oil among the significant HEFA oil crop feeds; livestock fats, including beef tallow, pork lard, and poultry fats; and fish oils—for which we analyze data on anchovy, herring, menhaden, salmon, and tuna oils.[1] Additionally, though it is a secondary product from various mixtures of these primary lipid sources, and its supply is too limited to meet more than a small fraction of current HEFA demand,[2] we include used cooking oil (UCO) in our analysis.[1]

2.2 Feedstock properties that affect HEFA jet fuel production

2.2.1 Feedstock carbon chain length

Jet fuel is a mixture of hydrocarbons that are predominantly in the range of eight to sixteen carbon atoms per molecule. In fuel chemistry shorthand, a hydrocarbon with 8 carbons is "C8" and one with 16 carbons is "C16," so the jet fuel range is C8–C16. Similarly, a fatty acid chain with 16 carbons is a C16 fatty acid. Thus, since fuels produced by the essential HEFA process steps—hydrodeoxygenation (HDO) and isomerization—reflect the chain lengths of fatty acids in the feed,[2] the ideal HEFA jet fuel feed would be comprised of C8–C16 fatty acids. But there is no such HEFA feedstock.

In fact, the majority of fatty acids in HEFA lipids feeds, some 53% to 95% depending on the feed, have chain lengths outside the jet fuel range.[1] This explains the low jet fuel yield problem with relying on HEFA technology for Sustainable Aviation Fuel (SAF) described in Chapter 1. However, that 53–95% variability among feeds also reveals that refiners could make more HEFA jet fuel from some HEFA feedstocks than from others.

2.2.2 Feedstock-driven process hydrogen demand

Options to increase HEFA jet fuel yield using intentional hydrocracking could be limited by hydrogen supplies available to refiners, and HDO, an essential HEFA process step, consumes hydrogen to saturate carbon double bonds in feeds and remove hydrogen from them (Chapter 1). HDO accounts for the majority of HEFA process hydrogen demand, and some HEFA feeds have more carbon double bonds, somewhat higher oxygen content, or both, compared with other HEFA feeds.[2] Thus, some HEFA feeds consume more process hydrogen, and thereby have more potential to affect jet fuel yield by limiting high-yield processing options, than other feeds.

2.3 Ranking HEFA feedstocks for jet fuel production

2.3.1 Effects on HDO yield

Table 1 summarizes results of our research for the chain length composition of fatty acids in HEFA feedstocks.[1] This table ranks feeds by their jet fuel range (C8–C16) fractions. Since fuels produced by the essential HDO and isomerization steps in HEFA processing reflect the chain lengths of HEFA feeds, the volume percentages shown in Table 1 represent potential jet fuel yield estimates for the processing strategy without intentional hydrocracking (No-IHC).

Table 1. Chain length[*] composition of fatty acid chains in HEFA feedstocks, ranked by jet fuel fraction.

	Jet fuel fraction (C8–C16) (volume % on whole feed)	Diesel fraction (C15–C18) (vol. %)	> C16 (vol. %)	>C18 (vol. %)
Palm oil	46.5	95.6	53.5	0.5
Menhaden oil	42.3	59.8	57.7	31.2
Tallow fat	33.3	95.2	66.7	0.4
Herring oil	32.7	49.3	67.3	42.7
Poultry fat	32.7	98.1	67.3	1.1
Anchovy oil	32.6	52.2	67.4	40.9
Tuna oil	31.5	48.9	68.5	44.5
Lard fat	30.0	96.5	70.0	2.1
Salmon oil	27.5	49.7	72.5	44.0
UCO 10th P.[*]	26.8	97.9	73.2	1.1
Cottonseed oil	25.7	98.7	74.3	0.4
Corn oil (DCO)[*]	13.6	98.9	86.4	1.1
UCO 90th P.[*]	12.9	99.2	87.1	0.8
Soybean oil	11.7	99.5	88.3	0.4
Canola oil	4.8	96.8	95.2	3.1
Yield-wtd. Average	**26.3**	**97.4**	**73.7**	**1.0**

[*] **Cx:** fatty acid chain of x carbons. **UCO:** used cooking oil. **10th P.:** 10th Percentile. **DCO:** Distillers corn oil. Data from Table 8, except world yield data by feed type for yield-weighted average shown from Table 7. Percentages do not add; fractions overlap.

Potential feed-driven effects on jet fuel yield shown in Table 1 range tenfold among feeds, from approximately 4.8% on feed volume for canola oil to approximately 46.5% for palm oil. For context, since supplies of some feeds shown are relatively low, it may be useful to compare high jet fuel yield feeds with soybean oil, the most abundant HEFA feed produced in the U.S.[2] Palm oil, the top ranked feed for jet fuel yield, could potentially yield nearly four times as much HEFA jet fuel as soybean oil, while menhaden fish oil and tallow might yield 3.6 times and 2.8 times as much jet fuel as soy oil, respectively. Again, this is for the No-IHC processing strategy.

2.3.2 Effects on IHC strategies yields

Feed-driven jet fuel yield effects could allow intentional hydrocracking (IHC) to further boost HEFA jet fuel yield, depending on the IHC processing strategy that refiners may choose. At 49.4 wt.% on feed (Chapter 1), or approximately 58 volume percent given the greater density of the feed than the fuel, IHC jet fuel yield exceeds those of the feed-driven effects shown in Table 1. But IHC adds substantially to the already-high hydrogen demand for essential HEFA process steps (Chapter 1). In this context, the eight highest-ranked feeds for jet fuel yield in Table 1 may allow a refiner without the extra hydrogen supply capacity to use IHC on its entire feed to use Selective-IHC on 53.5% to 70% of its feed. This indirect effect of feed-driven jet fuel yield on process configuration choices has the potential to further boost HEFA jet fuel yield.

Direct feedstock-driven effects on process hydrogen demand, which can vary by feed as described above, must be addressed along with this indirect effect. *See* Table 2 below.

Table 2. Hydrogen demand for hydrodeoxygenation (HDO) of HEFA feedstocks, grouped by HDO jet fuel and diesel hydrocarbon yields. Data in kilograms hydrogen per barrel of feed fraction (kg H_2/b)

Feedstock	Jet fraction (C8–C16)[a]		Diesel fraction (C15–C18)[a]		Longer chains (> C18)[a b]	
grouping	HDO kg/b[c]	Sat kg/b[d]	HDO kg/b[c]	Sat kg/b[d]	HDO kg/b[c]	Sat kg/b[d]
High jet/high diesel						
Palm oil	4.38	< 0.01	4.77	0.64	3.52	0.15
Tallow fat	4.53	0.14	4.70	0.62	3.62	0.19
Poultry fat	4.58	0.25	5.04	0.92	3.99	0.67
Lard fat	4.43	0.11	4.84	0.75	5.39	1.68
UCO (10th Pc.)	4.52	0.20	5.02	0.92	4.30	0.75
Cottonseed oil	4.30	0.02	5.47	1.34	3.51	0.16
High jet/low diesel						
Menhaden oil	4.72	0.28	5.07	0.85	8.64	4.83
Herring oil	4.77	0.30	5.09	0.89	6.11	2.52
Anchovy oil	4.72	0.28	5.22	1.02	8.07	4.31
Tuna oil	4.67	0.24	4.81	0.64	8.06	4.34
Salmon oil	4.51	0.09	5.18	1.01	7.99	4.27
Low jet/high diesel						
Corn (DCO) oil	4.27	0.01	5.60	1.48	4.87	1.38
UCO (90th Pc.)	4.35	0.09	5.56	1.45	3.38	0.00
Soybean oil	4.28	0.01	5.70	1.59	3.31	0.00
Canola oil	4.35	0.07	5.45	1.37	3.98	0.55

a. Feedstock component fractions based on carbon chain lengths of fatty acids in feeds. **b.** Fatty acid chains with more than 18 carbons (> C18), which might be broken into two hydrocarbon chains in the jet fuel range (C8–C16) by intentional hydrocracking (IHC). **c.** HDO: hydrodeoxygenation; hydrogen consumed in HDO reactions, including saturation. **d.** Sat: saturation, H_2 needed to saturate carbon double bonds in the feedstock component, included in HDO total as well and broken out here for comparisons between types of feeds. *See* Table 8 for details of data, methods, and data sources. Note that fatty acids with 15–16 carbons (C15–C16) are included in both the jet fuel and the diesel fuel ranges. **UCO:** Used cooking oil, a highly variable feed; the 10th and 90th percentiles of this range of variability are shown.

2.3.3 Effects on process hydrogen demand

Table 2 shows process hydrogen demand for HDO, and the portion of HDO accounted for by saturation of carbon double bonds, for fractions of each feedstock. The important detail this illustrates is that saturation of carbon double bonds—especially in the larger-volume diesel fraction and, for fish oils, the longer chain fraction—explains most of the differences in direct effects on hydrogen demand among feeds. At less than 1% to more than half of HDO hydrogen demand, saturation drives differences in hydrogen demand among feed fractions (Table 2). Further, these differences peak in the diesel and longer chain fractions of feeds (*Id.*), and the combined volumes of these diesel and longer chain fractions are both high for all feeds and variable among feeds (Table 1).

Since HDO is an essential step in all HEFA processing strategies (Chapter 1), this evidence that process hydrogen demand varies among feeds because of the processing characteristics of whole feeds means we can compare hydrogen demand across processing strategies based on whole feeds. Table 3 shows results from this comparison across processing strategies.

Table 3. Hydrogen demand in the no intentional hydrocracking (No-IHC), Selective IHC and Isom-IHC processing strategies by feed grouping and feed. ***kg H_2/b:*** *kilograms hydrogen/barrel whole feed*

Feedstock grouping	No-IHC [a] (kg H_2/b)	Selective-IHC [b] (kg H_2/b)	Isom-IHC [c] (kg H_2/b)
High jet/high diesel			
Palm oil	4.79	5.79	6.60
Tallow fat	4.71	6.11	6.70
Poultry fat	5.03	6.28	6.85
Lard fat	4.85	6.13	6.65
UCO (10th P.)	5.01	6.37	6.83
Cottonseed oil	5.44	6.84	7.28
High jet/low diesel			
Menhaden oil	6.18	7.30	8.02
Herring oil	5.50	6.76	7.33
Anchovy oil	6.37	7.67	8.23
Tuna oil	6.29	7.62	8.16
Salmon oil	6.40	7.78	8.25
Low jet/high diesel			
Corn (DCO) oil	5.58	7.19	7.42
UCO (90th P.)	5.55	7.17	7.39
Soybean oil	5.68	7.33	7.52
Canola oil	5.40	7.16	7.24
Feed-wtd. Average	5.24	6.62	7.07

a. Intentional hydrocracking (IHC) is not used. **b.** Intentional hydrocracking (IHC) is selective because in this strategy HDO output is separately isomerized, and only the non-jet fuel hydrocarbons from HDO are fed to IHC. **c.** Isomerization and IHC are accomplished in the same process step in this strategy; all HDO output, including the jet fuel fraction, is fed to intentional hydrocracking in this strategy. *See* Table 8 for details of data, methods, and data sources;[1] Table 7 for world feed data used to derive feed-weighted averages. **UCO:** Used cooking oil, a highly variable feed; 10th and 90th percentiles of range shown.

2.3.4 Interactions between feedstock and processing choices

Feedstock and process strategy choices combined can impact HEFA process hydrogen demand dramatically (Table 3). As expected, IHC increases hydrogen demand for all feeds, however, feed-driven and process strategy-driven effects overlap. The maximum feed-driven impact in the No-IHC strategy (6.40 kg H_2/b) exceeds the minimum (5.79 kg H_2/b) in the Selective-IHC strategy (*Id.*). Similarly, the maximum feed-driven impact in the Selective-IHC strategy (7.78 kg H_2/b) exceeds the minimum (6.60 kg H_2/b) in the Isom-IHC strategy (*Id.*). Hydrogen demand increases by approximately 75% from the lowest impact (4.71 kg H_2/b) to the highest impact (8.25 kg H_2/b) combination of feedstock and processing strategy (*Id.*).

Feed rankings for hydrogen demand differ from feed rankings for jet fuel yield (tables 1, 3). Palm oil ranks at the top for jet fuel yield and at or near the bottom for hydrogen demand while in contrast, fish oils are among the highest ranked feeds for both jet yield and hydrogen demand. Livestock fats are among the highest ranked feeds for jet fuel yield and among the lowest ranked feeds for hydrogen demand. The lowest ranked feeds for jet fuel yield, soybean and canola oils, are medium-ranked to high-ranked feeds for hydrogen demand.

Relatively lower hydrogen demand for palm oil and livestock fats across the columns in Table 3 further illustrates how interactions of feedstock and processing strategies can contribute to increased jet fuel yields. For example, the relative Isom-IHC hydrogen demand reduction achievable by switching from soybean oil to tallow (-0.82 kg/b; -10.9%) or from soybean oil to palm oil (-0.92 kg/b; -12.2%) can help to support the highest jet fuel yield processing strategy in situations where refinery hydrogen production capacity is marginally limited.

Results in Table 3 also reveal that some feedstocks switch rankings between the Selective-IHC strategy and other processing strategies. In one example, canola oil feedstock demands more hydrogen than cottonseed oil feedstock for Selective-IHC but slightly less than cottonseed oil for the No-IHC and Isom-IHC strategies (Table 3). This corresponds to the greater fraction of canola oil than cottonseed oil sent to intentional hydrocracking for the Selective-IHC strategy (see Table 1, > C16 vol. %).

Another example: Only some 57.7% of the total Menhaden oil feed volume goes to intentional hydrocracking for Selective-IHC, as compared with 88.3% of the soybean oil feed (*Id.*). Consequently, Menhaden oil demands less hydrogen than soybean oil for Selective-IHC but more hydrogen than soybean oil for the other processing strategies (Table 3).

Putting these direct and indirect feed-driven effects together, consider switching from soybean oil to tallow for Selective-IHC at a 50,000 to 80,000 b/d refinery—which is in the range of projects now proposed in California.[2] The direct effect on HDO from this soy oil-to-tallow switch, shown in the No-IHC column of Table 3 (-0.97 kg H_2/b), carries over to Selective-IHC. The indirect effect sends 21.6% less of the total tallow feed to hydrogen-intensive cracking for Selective IHC than that of soy oil (Table 1, > C16 fractions), further boosting hydrogen savings from the switch to -1.22 kg/b on total feed (Table 3). At feed rates of 50,000–80,000 b/d, this might save the refiner construction and operating costs for 61,000 to 97,600 kg/d of hydrogen capacity. Expressed as volume in millions of standard cubic feet per day (MMSCFD), that is the equivalent of a 24 to 38 MMSCFD hydrogen plant.

At the same time that switching from soy with No-IHC to tallow with Selective-IHC could enable the higher-yield processing strategy, however, net process hydrogen demand would increase by 0.43 kg/b (Table 3), an increase in this example of 8.4 to 13.5 MMSCFD.

Thus, examining feed and processing interactions reveals that switching to feeds with higher jet-range fractions, lower HDO hydrogen demand, or both enables refiners with limited hydrogen supplies to use intentional hydrocracking and thereby further boost jet fuel yields. More broadly, these results show refiners can make more HEFA jet fuel from some feedstocks than from others, but that doing so could result in substantially increased hydrogen demand for some combinations of feedstock and processing choices.

3. Does switching from one HEFA feedstock to another change processing carbon intensity differently when refiners target jet fuel instead of diesel production?

Switching feedstocks and production targets can affect the per-barrel emissions—the *carbon intensity*—of HEFA refining dramatically. The vast majority of direct CO_2 emission from HEFA refining emits from petroleum refinery steam reformers that refiners repurpose to supply HEFA process hydrogen demand.[2] The reformer emissions further increase with increasing hydrogen production.[2] As shown in Chapter 2, refiners could switch feeds to boost HEFA jet fuel yield in ways that increase refinery hydrogen demand differently compared with targeting HEFA diesel yield. This chapter evaluates the carbon intensity (CI) impacts of HEFA refining that could result from targeting HEFA jet fuel yield instead of diesel yield, and weighs their significance against the CI of petroleum refining.

3.1 CO_2 co-production and emission from hydrogen production by steam reforming

3.1.1 How steam reforming makes hydrogen

Steam reforming is a fossil fuel hydrogen production technology that co-produces CO_2. The process reacts a mixture of superheated steam and hydrocarbons over a catalyst to form hydrogen and CO_2. Hydrocarbons used include methane from natural gas, and it is often called steam methane reforming (SMR), but crude refiners use hydrocarbon byproducts from refining such as propane, along with methane from purchased natural gas, as feeds for the steam reformers that they could repurpose for HEFA processing.

3.1.2 How steam reforming emits CO_2

Both its CO_2 co-product and CO_2 formed in its fuel combustion emit from steam reforming. An energy-intensive process, steam reforming burns fuel to superheat process steam and feed, and burns more fuel for energy to drive pumps and support process reactions. Steam reforming fuel combustion emissions are reformer-specific and vary by plant. Based on verified permit data for 11 San Francisco Bay Area crude refinery steam reforming plants, we estimate median fuel combustion emissions of approximately 3.93 grams of CO_2 emitted per gram of hydrogen produced (g CO_2/g H_2), conservatively assuming methane fuel.[2] Co-product emissions are larger still, and vary by feed, with approximately 5.46 g CO_2/g H_2 emitting from methane feed and 6.56 g CO_2/g H_2 emitting from propane feed.[2] The coproduct and combustion emissions are additive.

3.1.3 Steam reforming CO_2 emission estimate

HEFA refinery steam reforming can be expected to use a feed and fuel mix that includes the propane byproduct from the process reactions discussed in Chapter 1 and natural gas methane. Based on process chemistry we conservatively assume 79% methane/21% propane feed with 100% methane fuel. From these figures we estimate typical HEFA steam reforming emissions of approximately 9.82 g CO_2/g H_2. This estimate is for repurposed crude refinery steam reformers, which are aging and may not be as efficient as newer steam reformers.[2] For context, however, our estimate is within 2.5% of a recent independent estimate of median emissions from newer merchant steam methane reforming plants, when compared on a same-feed basis.[2]

Thus, repurposed refinery steam reforming emits CO_2 at nearly ten times its weight in hydrogen supplied. With the high hydrogen demand for HEFA processing shown in Chapter 2, that is a problem. Since steam reforming emissions increase with increased production to meet increased hydrogen demand, the refining CI values reported below are based on the emission factor described above (9.82 g CO_2/g H_2) and the hydrogen demand data from Chapter 2.

3.2 Feedstock effects on CI resulting from HDO hydrogen demand

Hydrodeoxygenation (HDO) is an essential step, and is the major hydrogen consuming step, in all HEFA processing strategies (chapters 1 and 2). The data in Table 4 represent the HEFA processing strategy that uses HDO without intentional hydrocracking (No-IHC).

3.2.1 Feedstock HDO chemistry impact on HEFA refining CI

Table 4 shows effects of feedstock HDO chemistry on HEFA steam reforming emissions. Steam reforming-driven CI (kg/b: kg CO_2 per barrel feed) is substantially higher for whole feeds than for their jet fuel fractions. This is because the non-jet fractions need more hydrogen to saturate carbon double bonds and their combined volumes are larger than that of the jet fuel fraction (tables 1 and 2). Further, the extent of these differences between fractions varies among feeds (*Id.*). This is why feeds change ranks between the columns in Table 4. For example, the jet fuel fraction of palm oil has higher CI than that of soybean oil even though the whole feed data show that soybean oil is a higher CI feed. This variability among feed fractions also is why fish oil CI is high for both the jet fraction and the whole feed.

3.2.2 Need to account for whole feed impact

Does Table 4 show that palm oil could be a higher refining CI feed than soybean oil? No. Since the HDO step is essential for removing oxygen from the whole feed to co-produce both HEFA jet fuel and HEFA diesel, choosing any feed results in the CI impact of that whole feed.

Table 4. Hydrogen steam reforming emissions associated with the jet fuel fraction *v.* whole HEFA feeds in the HDO (No IHC) refining strategy; comparison of feed ranks by emission rate.

Jet fuel fraction (C8–C16)		Whole feed (≥ C8)	
Feed (rank)	CO_2 (kg/b feed)	Feed (rank)	CO_2 (kg/b feed)
Herring oil	46.8	Salmon oil	62.8
Menhaden oil	46.4	Anchovy oil	62.5
Anchovy oil	46.4	Tuna oil	61.7
Tuna oil	45.9	Menhaden oil	60.7
Poultry fat	45.0	Soybean oil	55.8
Tallow fat	44.5	Distillers corn oil	54.8
UCO (10th Percentile)	44.4	UCO (90th Percentile)	54.4
Salmon oil	44.3	Herring oil	54.0
Lard fat	43.5	Cottonseed oil	53.4
Palm oil	43.0	Canola oil	53.1
Canola oil	42.7	Poultry fat	49.4
UCO (90th Percentile)	42.7	UCO (10th Percentile)	49.2
Cottonseed oil	42.2	Lard fat	47.6
Soybean oil	42.0	Palm oil	47.1
Distillers corn oil	41.9	Tallow fat	46.2

C8–C16: fatty acid chains with 8 to 16 carbon atoms. **≥ C8:** fatty acid chains with 8 or more carbon atoms. **Menhaden:** a fish. **UCO:** used cooking oil, a variable feed; 10th and 90th percentiles shown. Data from Table 2 at 9.82 g CO_2/g H2 steam reforming.

While the jet fuel fraction data in this table helps to inform why feed quality impacts refining CI, we need to account for those CI impacts of whole feeds shown in Table 4.

3.2.3 High-jet feeds can increase or decrease HDO-driven CI

HDO-driven CI findings for whole feeds reveal mixed CI results for high-jet fuel yield feedstocks in No-IHC processing. Fish oils rank highest for steam reforming-driven CI while livestock fats and palm oil rank lowest (Table 4). Thus, for this processing strategy, switching feeds to boost jet fuel yield can increase or decrease refining CI. However, No-IHC also is the processing strategy that HEFA refiners use to maximize diesel yield rather than jet fuel yield. Feedstock quality interacts with other processing choices in different ways that could further boost HEFA refining CI along with jet fuel yield, as shown below.

3.3 Feedstock effects on CI resulting from Selective-IHC hydrogen demand

3.3.1 Process strategy impact of high-jet feeds

High jet yield feeds result in less input to Selective-IHC, enabling marginally hydrogen-limited refiners to further boost jet fuel yield via Selective-IHC, but this requires additional hydrogen (chapters 1 and 2). Intentional hydrocracking (IHC) thus increases hydrogen steam reforming rates and emissions, increasing refining CI for all feeds, as shown in Table 5. This impact overlies the HDO impact, so that feed CI values overlap between columns. For example, the tuna oil No-IHC CI (61.7 kg/b) exceeds the tallow Selective-IHC CI (60.0 kg/b), and the anchovy oil Selective-IHC CI (75.3 kg/b) exceeds the soy oil Isom-IHC CI (73.9 kg/b).

Table 5. Hydrogen steam reforming emissions from the No-IHC, Selective-IHC, and Isomerization IHC refining strategies: comparisons of whole HEFA feed ranks by emission rate.

No-IHC		Selective-IHC		Isomerization-IHC	
Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)
Salmon oil	62.8	Salmon oil	76.4	Salmon oil	81.0
Anchovy oil	62.5	Anchovy oil	75.3	Anchovy oil	80.8
Tuna oil	61.7	Tuna oil	74.8	Tuna oil	80.1
Menhaden oil	60.7	Soybean oil	72.0	Menhaden oil	78.8
Soybean oil	55.8	Menhaden oil	71.6	Soybean oil	73.9
Corn oil–DCO	54.8	Corn oil-DCO	70.6	Corn oil-DCO	72.8
UCO 90th P.	54.4	UCO 90th P.	70.4	UCO 90th P.	72.6
Herring oil	54.0	Canola oil	70.3	Herring oil	72.0
Cottonseed oil	53.4	Cottonseed oil	67.2	Cottonseed oil	71.5
Canola oil	53.1	Herring oil	66.4	Canola oil	71.1
Poultry fat	49.4	UCO 10th P.	62.5	Poultry fat	67.2
UCO 10th P.	49.2	Poultry fat	61.7	UCO 10th P.	67.1
Lard fat	47.6	Lard fat	60.2	Tallow fat	65.7
Palm oil	47.1	Tallow fat	60.0	Lard fat	65.3
Tallow fat	46.2	Palm oil	56.9	Palm oil	64.8

IHC: Intentional hydrocracking. **No-IHC:** CO_2 from hydrodeoxygenation (HDO). **Selective-IHC:** CO_2 from HDO plus IHC of HDO output hydrocarbons > C16. **Isomerization-IHC:** CO_2 from HDO plus IHC of all HDO output (> C8). **Menhaden:** a fish. **UCO:** used cooking oil, 10th, 90th percentiles shown. **DCO:** distillers corn oil. Figures shown exclude emissions associated with H_2 losses, depropanation, and inadvertent cracking. Data from Table 3 at 9.82 g CO2/g H2 steam reforming.

3.3.2 Feed chemistry effects on feed rankings for CI

Feedstock CI rankings differ between No-IHC and Selective-IHC processing (Table 5). This is a feed quality impact driven primarily by the different volumes of non-jet fractions sent to IHC among feeds. It boosts the CI of soybean oil from 4.9 kg/b below to 0.4 kg/b above the CI of menhaden oil with the addition of Selective-IHC (*Id.*). With 88.3% of its volume outside the jet fuel range compared with 57.7% of menhaden oil (Table 1, > C16 fractions), soy oil sends 30.6% more feed to Selective-IHC than menhaden oil. More IHC feed requires more hydrogen, boosting steam reforming emissions more with soy than with menhaden oil. Similarly, canola oil sends 27.9% more feed to Selective-IHC than herring oil (*Id.*). This boosts canola oil CI from 0.9 kg/b below to 3.9 kg/b above herring oil CI with the addition of Selective-IHC (Table 5).

3.3.3 How livestock fat feeds could affect soy oil and canola oil refining CI

When switching from soy or canola oil to livestock fat enables a refiner to boost jet fuel yield by repurposing its refinery for Selective-IHC processing, that intentional hydrocracking can boost jet yield from soy and canola oil feeds as well. Thus, instead of shutting down when, for any reason at any time, livestock fat becomes too scarce or expensive, the refiner could make jet fuel by going back to soybean oil or canola oil feedstock. This could increase refining CI by 16.2 kg/b (29%) for soy oil, and 17.2 kg/b (32%) for canola oil, based on our results for the Selective-IHC *versus* No-IHC processing strategies in Table 5.

3.4 Feedstock effects on CI resulting from Isom-IHC hydrogen demand

Livestock fat and palm oil could maximize jet fuel yield by enabling Isom-IHC processing, since these feeds minimize HDO hydrogen demand (chapters 1 and 2). Their relatively lower non-jet fractions do not contribute to this effect on Isom-IHC because, in contrast to Selective-IHC, Isom-IHC processes the entire feed stream output from HDO. Direct effects of feed quality variability on Isom-IHC cracking are relatively weak, since HDO both saturates and removes oxygen from Isom-IHC inputs. Thus, the relative feed rankings for CI from No-IHC processing carry over to the Isom-IHC feed rankings with only minor differences (Table 5). However, by cracking of the entire HDO output, Isom-IHC further boosts hydrogen demand, thus hydrogen steam reforming emissions, resulting in the highest HEFA refining CI for all feeds (*Id.*).

Across feeds and process options, from the lowest to the highest impact combinations of feeds and processing, HEFA refining CI increases by 34.8 kg CO_2/b (75%), and CI increases in 122 (79.7%) of 153 feed switching combinations that could boost jet fuel yield (tables 1, 3, 5).

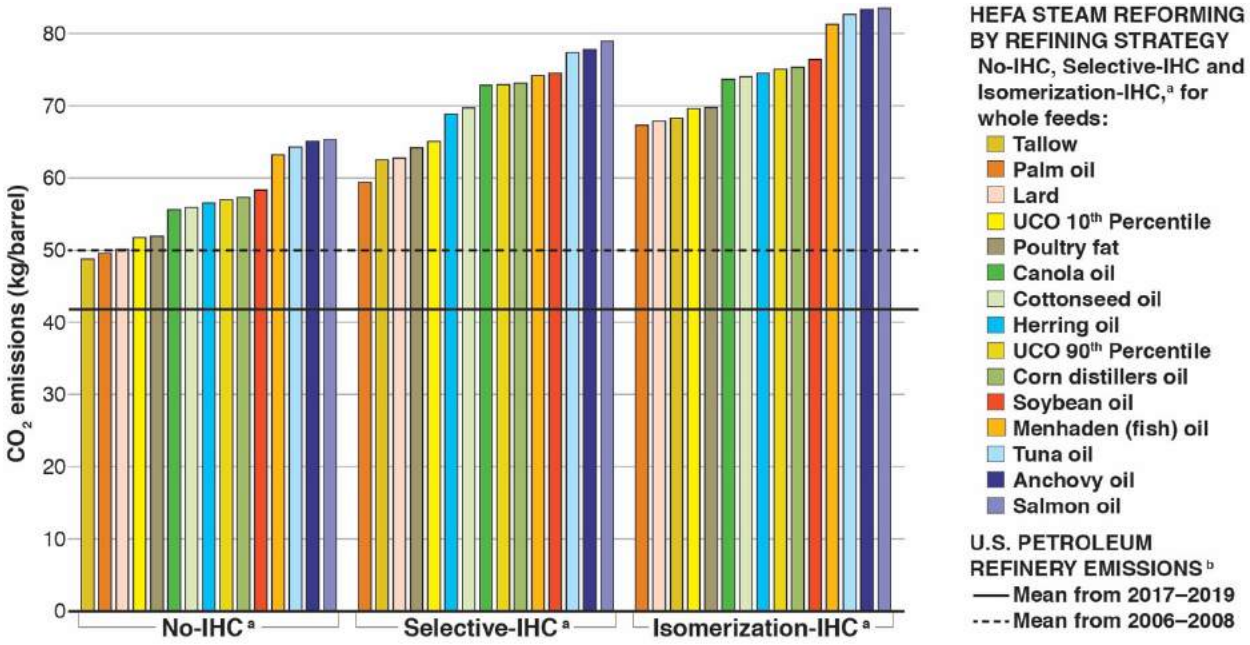
3.5 Comparison with petroleum refining CI by feedstock and processing strategy

Chart 1 plots results for feedstock-related impacts on the variability of HEFA refining CI from HEFA steam reforming emissions against the CI of U.S. petroleum refining. Our results in Table 5 are shown by processing strategy and, within each strategy, each feed is represented by a color-coded column. The height of the column represents the contribution of steam reforming to HEFA refining CI for that particular feed and processing strategy. The solid black line shown at approximately 41.8 kg/b (kg CO_2/barrel crude processed) represents the average U.S. petroleum refining CI from 2015 through 2017.[6] We use this (41.8 kg/b) as our benchmark. For added context, average U.S. petroleum refining CI from 2006–2008,[7] a period when the U.S. refinery crude slate was denser and higher in sulfur than during 2015–2017[8] resulting in higher historic U.S. crude refining industry CI,[7] is represented by the dashed line at 50 kg/b in the chart.

Please note what HEFA emissions Chart 1 does and does not show. It shows HEFA refining steam reforming emissions only. This helps us focus on our question about refining CI impacts from HEFA feedstock switching to target jet fuel, which are directly related to HEFA steam reforming rates. It *does not* show total direct emissions from HEFA refining.

3.5.1 HEFA refining CI impacts are significant compared with crude refining

Other HEFA refining emissions besides those from steam reforming—from fuel combustion to heat and pressurize HEFA hydro-conversion reactors, precondition and pump their feeds, and distill and blend their products—could add roughly 21 kg/b of additional HEFA refining CI.[2] Thus, for a rough comparison of petroleum refining CI with total HEFA refining CI, imagine adding 21 kg/b to the top of each column in Chart 1. HEFA refining CI approaches or exceeds *double* the CI of petroleum refining. Clearly, expanding HEFA jet fuel would increase the CI of hydrocarbon fuels processing substantially.



1. HEFA Steam Reforming Emissions *v.* Total U.S. Petroleum Refining Emissions, kg CO_2/barrel feed input.

a. HEFA steam reforming emissions only: values shown exclude CO_2 emitted by other HEFA refining process and support equipment. This contrasts with the petroleum refining emissions shown, which include all direct emissions from crude refining. Including all direct emissions from HEFA refining could increase the HEFA estimates shown by approximately 21 kg/barrel.[2] The "No-IHC" strategy excludes intentional hydrocracking (IHC); the "Selective-IHC" strategy adds emission from producing hydrogen consumed by intentional hydrocracking of feed fractions comprised of hydrocarbons outside the jet fuel range; the "Isomerization-IHC" strategy adds emissions from intentional hydrocracking of whole feeds in the isomerization step of HEFA fuels production. HEFA data shown include feed-driven emissions in Table 5 plus additional steam reforming emissions (2.5 kg/b) from producing the additional hydrogen that is lost to unintended side-reaction cracking, solubilization, scrubbing and purging (*see* Table 8).[1]

b. U.S. petroleum refinery emissions including total direct CO_2 emitted from steam reforming and all other petroleum refinery process and support equipment at U.S. refineries. Mean from 2015 through 2017 based on total refinery emissions and distillation inputs reported by the U.S. Energy Information Administration (EIA).[6] Mean from 2006 through 2008 represents a period of historically high-carbon U.S. refining industry crude inputs.[7] [8]

3.5.2 High-jet feed impacts on processing targeting jet fuel can increase refining CI

Feeds that enable intentional hydrocracking to boost jet fuel yield could increase HEFA refining CI significantly (Chart 1). Here we report feed switching CI increments compared with No-IHC processing of soy and canola oils to target diesel yield (*see* Table 5) as percentages of our petroleum crude refining benchmark: Switching to Selective IHC with anchovy and salmon oils increases CI by 47% to 56% (of crude refining CI) while switching to Selective IHC with menhaden oil increases CI by 38% to 44%. Switching to Isom-IHC with tallow increases CI by 24% to 30% while switching to Isom-IHC with palm oil increases HEFA refining CI by 21% to 28% of crude refining CI. Switching to Selective-IHC with tallow increases CI by 10% to 17%. Only Selective-IHC with palm oil has similar CI to that of No-IHC with soy oil (+3%).

3.5.3 High-jet feed CI impacts are mixed in processing targeting HEFA diesel yield

Compared with No-IHC processing of soy or canola oils, which are the combinations of processing and feeds that maximize HEFA diesel yield, No-IHC with fish oils could increase refining CI while No-IHC with palm oil or livestock fats could decrease CI. For example, switching to anchovy oil could increase No-IHC HEFA refining CI over that of canola and soy oils by 16% to 23% of crude refining CI while switching to tallow could decrease it by 16% to 23% of crude refining CI. But there is a caveat to those estimates.

In theory, feeding tallow to No-IHC processing could boost jet fuel yield to one-third of feedstock volume (Table 1) while lowering CI by 6.8 or 9.5 kg/b below canola or soy oil in No-IHC processing, the strategies refiners use to maximize HEFA diesel yield. However, this would require three barrels of tallow feed per barrel of jet fuel yield, emphasizing a crucial assumption about HEFA biofuel as a sustainable jet fuel solution—it assumes a sustainable feedstock supply. That assumption could prove dangerously wrong, as shown in Chapter 4.

4. HEFA jet fuel feedstock and carbon sinks: Could the feedstocks that maximize HEFA jet fuel instead of diesel yield have comparatively high indirect climate impacts?

Increasing demand for limited supplies of feedstocks that refiners could use to boost HEFA jet fuel yield and make more HEFA jet fuel risks increasing deforestation and other serious indirect climate impacts. HEFA biofuel feedstocks are purpose-derived lipids also needed for food and other uses,[9] [10] are globally traded, and can increase in price with increased biofuel demand for their limited supply.[2] Ecological degradation caused by expanded production and harvesting of the extra lipids for biofuels has, in documented cases, led to emissions from natural carbon sinks due to biofuels. Those emissions have traditionally been labeled as an "indirect land use impact," but as shown above, refiners seeking to maximize HEFA jet fuel production also could use fish oil feedstocks. The term "indirect carbon impacts," meant to encompass risks to both terrestrial and aquatic carbon sinks, is used in this chapter.

4.1 Natural carbon sinks that HEFA jet fuel feedstock acquisition could affect

Feedstocks that increase HEFA jet fuel production could have indirect impacts on land-based carbon sinks, aquatic carbon sinks, or both. At the same time the impact mechanisms differ between terrestrial and aquatic ecosystems. Part 4.1.1 below discusses carbon sink risks due to land degradation, and part 4.1.2 discusses carbon sink risks due to fishery depletion.

4.1.1 Land degradation risks: Carbon sinks in healthy soils and forests

Even before new Sustainable Aviation Fuel plans raised the potential for further expansion of HEFA feedstock acquisition, biofuel demand for land-based lipids production was shown to cause indirect carbon impacts. A mechanism for these impacts was shown to be global land use change linked to prices of commodities tapped for both food and fuel.[11] Instead of cutting carbon emissions, increased use of some biofuel feedstocks could boost crop prices, driving crop and pasture expansion into grasslands and forests, and thereby degrading natural carbon sinks to result in biofuel emissions which could exceed those of petroleum fuels.[11]

Indirect carbon impacts of lipid feedstocks which further HEFA biofuel expansion could tap have been observed and documented in specific cases. International price dynamics involving palm oil, soybean oil, biofuels and food were linked as factors in the deforestation of Southeast Asia for palm oil plantations.[12] Soy oil prices were linked to deforestation of the Amazon and Pantanal in Brazil for soybean plantations.[13] [14] [15] Demand-driven changes in European and U.S. prices were shown to act across the oil crop and animal fat feedstocks for HEFA biofuels.[16] Rapeseed (canola) and soy biofuels demand drove palm oil expansion in the Global South as palm oil imports increased for other uses of those oils displaced by biofuels in the Global North.[17] Indirect land use impacts of some soy oil—and most notably, palm oil—biofuels were found to result in those biofuels emitting more carbon than petroleum fuels they are meant to replace.[17] [18] [19] Current U.S. policy discourages palm oil-derived biofuel for this reason.[20]

As of 2021, aerial measurements suggest that combined effects of deforestation and climate disruption have turned the southeast of the great Amazonian carbon sink into a carbon source.[21] Market data suggest that plans for further HEFA biofuels expansion have spurred an increase in soybean and tallow futures prices.[22] [23] [24] A joint report by two United Nations-sponsored bodies, the Intergovernmental Panel on Climate Change and the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services, warns that expansion of industrial biofuel feedstock plantations risks inter-linked biodiversity and climate impacts.[25]

Moreover, these risks are mutually reinforcing. Potential pollinator declines,[26] climate heating-driven crop losses,[27] biofuel policy-driven food insecurity,[28] and the prospect that, once a biofuel also needed for food is locked into place, retroactive limits on land use conversion could worsen food insecurity,[11] reveal another aspect of this carbon sink risk. Namely, the assumption asserted by HEFA biofuel proponents, that we can "grow our way out" of limits on biomass diversion to biofuels by increasing crop yields and reverse course later if that does not work, risks lasting harm.

4.1.2 Fishery depletion risks: The biological carbon pump in world oceans

Increasing demand for fish products could further drive fisheries depletion, thereby risking substantial emissions from the oceanic carbon sink. This potential impact, like that on terrestrial carbon sinks, has received intensifying scientific attention in recent years, but appears to remain less widely known to the general public. Fished species have crucial roles in the mechanisms that send carbon into the oceanic carbon sink, as shown below.

Oceans account for 71% of the Earth surface[29] and remove roughly one-fourth to one-third of total carbon emissions from all human activities annually.[30] [31] A portion of the CO_2 exchange between air and water at the sea surface is sequestered in the deep seas via inter-linked shallow, mid-reach, and benthic ecosystems that comprise a "biological pump" in which fished species play key roles. *See* Illustration 1.

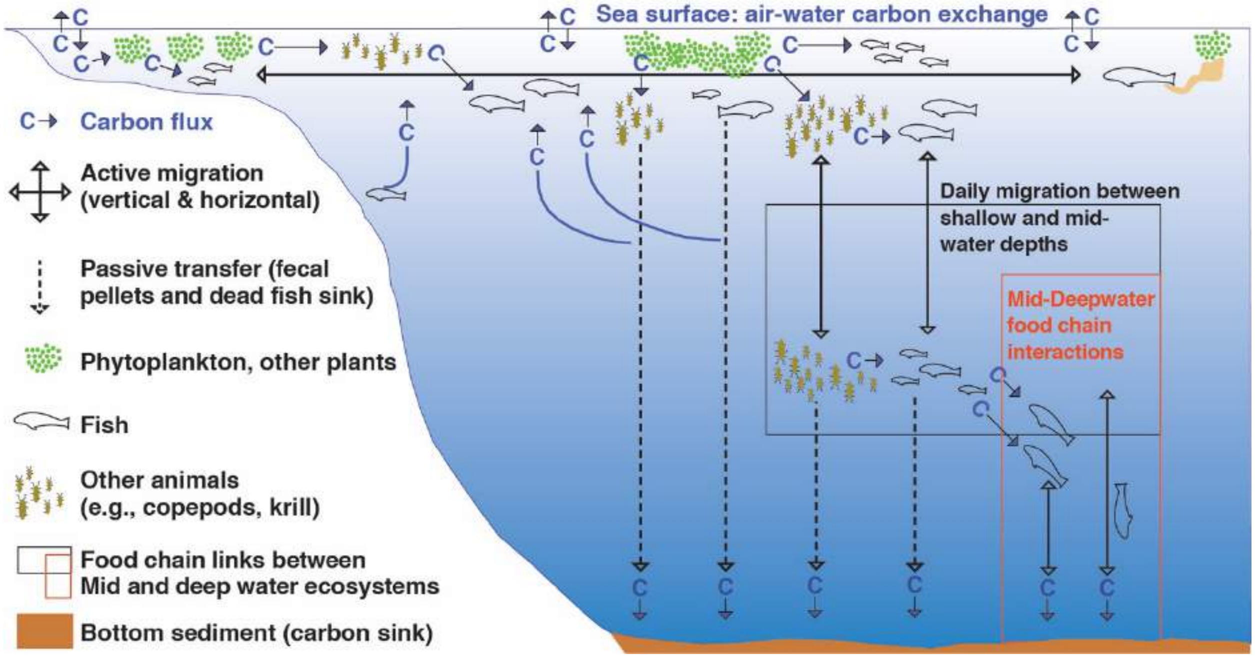


Illustration 1. Biological pump to the deep oceans carbon sink

Fish have key roles in the inter-linked shallow, mid-reach, and benthic ecosystems that drive a "biological pump" which sends carbon into the deep seas. In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants, then by animals in aquatic food webs, and horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake. Some of this carbon falls to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown), while respiration releases CO_2 from aquatic animals and from bacterial degradation of fecal matter (upward-curving lines), some of which re-enters the atmosphere at the sea surface. Active vertical migration (solid vertical lines) further drives the biological pump. A substantial portion of both fish and their invertebrate prey biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight—where deep-sea fish species migrate and feed as well (black and red boxes). Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea. The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.

In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants and then by animals in ocean food webs. (Illustration, top.) Horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake (*Id.*).[25][31] Some of this carbon sinks to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown)[25][32] but not all of it; some of the CO_2 released in respiration by aquatic animals and bacterial degradation of fecal matter re-enters the atmosphere at the sea surface (upward-curving lines).[30][32] That sea surface carbon exchange emphasizes the role of active vertical migration (solid vertical lines) in the biological pump.

For both fish and their invertebrate prey, a substantial portion of their ocean biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight[25]—where deep-sea fish species migrate and feed as well.[32] Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea.[25 30 32] The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.[25 30 32]

Although impacts are not yet fully quantified,[25] at present—even at "maximum sustainable yield"—fishery depletion impacts the oceanic carbon sink by removing roughly half of the fisheries biomass that would otherwise be in world oceans.[25 31] This exports the carbon in fish from ocean sequestration to land, where that exported carbon then enters the atmosphere.[25 31] Fished species are targeted selectively, disrupting ecosystems involved in the biological pump and potentially reducing both the passive and the active transport of carbon to deep sea carbon sequestration.[25 32] Worse, as demands for limited fisheries catches have grown, bottom trawling, which directly disrupts and releases carbon from ocean sediments, may already have reduced the oceanic carbon sink by as much as 15–20%.[25] In this context fish oil demand, while only a small fraction of total fisheries catch, is still supplied more from whole fish than from fish byproducts, and is projected to grow by a few percentage points through 2030.[10] Thus, potential additional fish oil demand for biofuel poses an indirect carbon impact risk.

4.2 Historic impact assessments for high jet fuel yield HEFA feedstocks

HEFA refiners could maximize jet fuel instead of diesel production using palm oil, fish oil, or livestock fats for feedstocks, as shown in Chapter 2 above. Historic demand for these specific feedstocks has resulted in relatively high indirect carbon impacts from one of them, and raises questions about future impacts from increased demand for the other two high jet fuel yield feeds.

4.2.1 Palm oil: High jet fuel yield, high impact and current use restriction

With 46.5% of its fatty acid feedstock volume comprised of carbon chains in the jet fuel range, palm oil ranks first among major HEFA feedstocks for the potential to increase HEFA jet fuel production. See Table 1. Palm oil also has perhaps the highest known potential among HEFA feedstocks for indirect land use impacts on natural carbon sinks (§ 4.1.1). Some palm oil-derived biofuels have reported fuel chain carbon intensities that exceed those of the petroleum fuels they are meant to replace (*Id.*). However, current U.S. policy restricts the use of palm oil-derived biofuels to generate carbon credits due in large part to this high indirect carbon impact.[20] Future biofuel demand could affect the efficacy of this use restriction.

4.2.2 Fish oil: High jet fuel yield and low carbon impact assumed for residual supply

Fish oils rank second, fourth, sixth, seventh and ninth for jet fuel-range fractions at 42.3%, 32.7%, 32.6% and 27.5% of their feed volumes. See Table 1. Moreover, their relatively low diesel fractions (48.9–59.8%) and relatively high feed fractions with carbon chains longer than the ideal diesel range, which could be broken into twin jet fuel hydrocarbons (*Id.*), might favor jet fuel production by intentional hydrocracking strategies. Current biofuel use of fish oil is low, and is assumed to be residual biomass, and thus to have relatively low indirect carbon impact. However, that assumption is based on historic fish oil usage patterns at historic biofuel demand. If HEFA refiners seek to maximize jet fuel production by tapping fish oil in larger amounts, this has a potential to result in high indirect carbon sink risk by further depleting fisheries that contribute to the biological pump which sequesters carbon in the deep sea (§ 4.1.2).

4.2.3 Livestock fat: High jet fuel yield and low carbon impact assumed for residual supply

Tallow, poultry fat, and lard rank third, fifth, and eighth for jet fuel-range fractions at 33.3%, 32.7%, and 30% of their feed volumes, respectively. *See* Table 1. For these livestock fats, HEFA feedstock acquisition impact and supply estimates are linked by the assumption that only "waste" residues of livestock fat biomass will be used for biofuels.[33] [34] This results in lower estimates for feedstock acquisition impacts by assuming that impacts from using farm and pastureland to feed the livestock are assigned to other uses of the livestock, such as food. At the same time, this assumption limits the supply for biofuels to only "waste" which, it is assumed, will not result in using more land for livestock feed in response to increased HEFA feedstock demand. These current assumptions—that increased demand will not cause land use impacts because it will not increase livestock production—limit current estimates of both supply and indirect carbon impact. Again, however, the current assumptions driving indirect carbon impact estimates are based on historic lipids usage patterns, which may change with increasing HEFA feedstock demand.

4.3 Feedstock acquisition risks to carbon sinks could be substantial at usage volumes approaching the current HEFA jet fuel blend limit

Impacts of these differences among feedstocks—and HEFA feedstock acquisition impacts overall—depend in large part upon future HEFA demand for limited current feedstock supplies. Moreover, indirect carbon impacts can include impacts associated with displacing other needs for these lipid sources, notably to feed humans directly and to feed livestock or aquaculture fish. This section compares potential HEFA SAF feedstock demand with limited current lipid supplies to assess potential indirect carbon impacts of specific and combined HEFA feedstocks.

4.3.1 Potential future HEFA jet fuel feedstock demand in the U.S.

SAF implementation could drive dramatic HEFA feedstock demand growth. In 2019, the most recent year before COVID-19 disrupted air travel, U.S. SAF consumption was estimated at 57,000 barrels,[35] only 0.009% of the 636 million barrels/year (MM b/y) U.S. jet fuel demand.[36] Since SAF must be blended with petroleum jet fuel and can be a maximum of half the total jet fuel,[35] implementation of SAF goals could result in future jet biofuel production of as much as 318 MM b/y assuming no growth in jet fuel demand. This would represent SAF growth to approximately 5,580 *times* the 2019 SAF biomass demand. HEFA technology is on track to claim the major share of this prospective new biomass demand.

Since 2011, "renewable" diesel production used in California alone, a surrogate for U.S. HEFA biofuel use,[35] grew by a factor of 65 times to 2.79 MM b/y as of 2013, by 142 times to 6.09 MM b/y as of 2016, and 244 times to 10.5 MM b/y as of the end of 2019.[37] Planned new HEFA capacity targeting the California fuels market and planned for production by 2025 totals approximately 124 MM b/y,[38] another potential increase of more than tenfold from 2019–2025.

Financial incentives for oil companies to protect their otherwise stranded refining assets are a major driver of HEFA growth—for example, in the two biggest biorefineries to be proposed or built worldwide to date.[2] More crude refining asset losses can thus spur more HEFA growth.[2]

Further idling of crude refining assets is indeed likely. Climate constraints drive the need to replace gasoline, with most credible expert assessments showing approximately 90% of gasoline to be replaced in mid-century climate stabilization scenarios.[39] [40] [41] [42] More efficient electric vehicles with lower total ownership costs will force gasoline replacement as vehicle stock rolls over, and this independent driver could replace approximately 80% of U.S. gasoline vehicles by mid-century.[2] Designed and built to co-produce gasoline and maximize gasoline production, U.S. crude refineries cannot produce distillates alone and will be idled as gasoline is replaced.[2]

Refiners can—and would be highly incentivized to—protect those otherwise stranded assets by repurposing their crude refining equipment for HEFA biofuel production. Assuming the low end of the mid-century crude refining asset loss projections noted above, 80% of existing U.S. refinery hydrogen production capacity could be repurposed to supply approximately 2.66 million metric tons per year (MM t/y) of hydrogen for HEFA production at idled and repurposed crude refineries. *See* Table 6 below.

Depending on the mix of HEFA jet fuel processing strategies that the prospective new HEFA refining fleet might employ, this much repurposed hydro-conversion capacity could make enough HEFA jet fuel to replace 36% to 39% of total U.S. jet fuel demand, assuming no growth from 2019 demand. *Id.* Notably, if the existing[37] and planned[38] capacity through 2025 is built and tooled for the same jet fuel yields, this mid-century projection implies a threefold HEFA capacity growth rate from 2026–2050, slower than the tenfold growth planned from 2019–2025.

In order to "book-end" an uncertainty previewed in chapters 1 and 2 above, Table 6 shows two potential HEFA jet fuel growth scenarios. Scenario S-1 assumes a future U.S. HEFA refining fleet with 30% of refineries using the No-IHC strategy and 70% using the Isom-IHC strategy. This scenario assumes many refiners that repurpose for HEFA production lack existing equipment to repurpose for intentional hydrocracking separately and in addition to the hydro-deoxygenation and isomerization reactors needed for all HEFA processing, and refiners choose not to build new hydrocracking capacity into their asset repurposing projects. Scenario S-2 assumes the opposite: many refiners have that existing capacity or choose to build new capacity into their repurposing projects, resulting in a mix with 20% of refineries using the No-IHC strategy, 70% using the Selective-IHC strategy, and 10% using the Isom-IHC strategy.

Relying mainly on Selective-IHC, which cuts hydrogen demand compared with Isom-IHC, Scenario S-2 makes more jet fuel from the same amount of repurposed hydrogen capacity, but nevertheless, at 71–72 MM t/y, feedstock demand is very high in both scenarios (Table 6).

Table 6. Potential HEFA jet fuel growth scenarios to mid-century in the U.S.

t: metric ton **MM t/y:** million metric tons/year

Total U.S. crude refining hydrogen plants capacity in 2021 (MM t/y) [a]					3.32
Assumption by 2050: 80% repurposed for HEFA biofuel (MM t/y)					2.66
Scenario S-1: No use of selective and intentional hydrocracking (Selective-IHC) [a]					
Process strategy		No-IHC	Selective-IHC	Isom-IHC	Total
Refineries breakdown	(% feed)	30 %	0 %	70 %	100 %
Hydrogen input [b]	(kg/t feed)	9.04	0.00	28.5	37.5
Feed input [b]	(MM t/y)	21.3	0.00	49.7	71.0
Jet fuel yield [c]	(MM t/y)	4.75	0.00	24.5	29.3
HEFA jet fuel production in the U.S. as a percentage of total 2019 U.S. jet fuel demand:					36 %
Scenario S-2: High use of selective and intentional hydrocracking (Selective-IHC) [a]					
Process strategy		No-IHC	Selective-IHC	Isom-IHC	Total
Refineries breakdown	(% feed)	20 %	70 %	10 %	100 %
Hydrogen input [b]	(kg/t feed)	6.02	26.6	4.06	36.7
Feed input [b]	(MM t/y)	14.5	50.7	7.25	72.4
Jet fuel yield [c]	(MM t/y)	3.23	25.0	3.58	31.8
HEFA jet fuel production in the U.S. as a percentage of total 2019 U.S. jet fuel demand:					39 %

Absent policy intervention, given renewable incentives and assuming severe feed supply limitations are overcome, U.S. HEFA jet fuel production could replace 36–39% of current U.S. petroleum jet fuel, and demand 71–72 million tons/year of lipids feedstock annually, by mid-century. Crude refiners could be highly incentivized to repurpose assets, which would be stranded by climate constraints and electric vehicles, for HEFA biofuels; less clear is the mix of processing strategies the repurposed HEFA refining fleet would use. Refiners could boost jet fuel yield by intentional hydrocracking of HEFA isomerization feeds (Isom-IHC), or do so while limiting hydrogen costs by intentional hydrocracking of selected feed fractions separately from the isomerization step needed for all fractions (Selective-IHC). However, some refineries lack existing equipment for one or both IHC options and may not choose to build onto repurposed equipment. Scenarios in this table span a conservatively wide range of fleet-wide processing strategies in order to "book-end" this uncertainty, resulting in the feed and fuel ranges shown above. The 80% petroleum capacity idling assumed by 2050[2] is generally consistent with highly credible techno-economic analyses, which, however, generally assume a different biofuel technology and feedstock source.[40–42] **a.** U.S. refinery hydrogen capacity from *Oil & Gas Journal.*[5] **b.** Hydrogen and feed inputs based on feed-weighted data from Table 3 and a feed blend SG of 0.914. **c.** Jet fuel yields based on yield-wtd. data from Table 1 at 0.775/0.914 jet/feed SG (No-IHC) and Pearlson et al. (IHC).[3] U.S. jet fuel demand in 2019 from USEIA (636.34 MM bbl),[36] or 81.34 MM t/y at the petroleum jet fuel density in the survey reported by Edwards (0.804 SG).[43] Diesel is the major HEFA jet fuel coproduct. Figures shown may not add due to rounding.

4.3.2 Limited HEFA jet fuel feedstock supplies in the U.S. and world

Current feedstock supplies limit the sustainability of HEFA jet fuel as a substantial component of U.S. jet fuel at rates well below the 50% SAF blend limit. Total current U.S. lipids production for all uses could supply only 29% of the feedstock needed for HEFA jet fuel to replace 36% to 39% of 2019 U.S. jet fuel use, as shown for scenarios S-1 and S-2 in Table 7 below. Other uses of these lipids crucially involve direct and indirect human needs for food, and in these scenarios, U.S. HEFA biofuel alone displaces one-third of all other existing lipids usage globally (Table 7).

Further, at even half the HEFA jet fuel production rates shown in Table 7, current global production of no one lipid source can supply the increased biofuel feedstock demand without displacing significant food system resources. This observation reveals the potential for impacts that cut across multiple prospective HEFA feedstock sources.

Table 7. HEFA feedstock demand in potential U.S. petroleum jet fuel replacement scenarios compared with total current U.S. and world production for all uses of lipids.

MM t/y: million metric tons/year

U.S. Feedstock Demand Scenarios [a]	No 100% Replacement NA: blend limit		36% Scenario S-1 71.0 MM t/y		39% Scenario S-2 72.4 MM t/y	
Current Feedstock Supply	**U.S. (MM t/y)**	**World (MM t/y)**	**Supply / Demand (%) U.S.**	**Supply / Demand (%) World**	**Supply / Demand (%) U.S.**	**Supply / Demand (%) World**
Palm oil [b]	0.00	70.74	0%	99%	0%	98%
Fish oil [c]	0.13	1.00	0.18%	1.4%	0.18%	1.4%
Livestock fat [d]	4.95	14.16	7%	20%	7%	20%
Soybean oil [e]	10.69	55.62	15%	78%	15%	77%
Other oil crops [e]	5.00	73.07	7%	103%	7%	101%
Total Supply	20.77	214.59	29%	309%	29%	302%

Total current U.S. production for all uses of lipids also tapped for biofuel could supply only 29% of potential U.S. HEFA jet fuel feedstock demand in 2050. **a.** HEFA feedstock demand data from Table 6. **b.** Palm oil data from Oct 2016–Sep 2020.[44] **c.** Fish oil data from 2009–2019 (U.S.)[45] and unspecified recent years (world).[46] **d.** Livestock fat data from various dates (US)[9] and 2018 (world).[47] **e.** Soybean oil, palm oil, and other oil crops data from unspecified dates for used cooking oil (US),[9] Oct 2016–Sep 2020 for oil crops also used for biofuel (US),[48] and Oct 2016–Sep 2020 for oilseed crops (world).[44]

4.3.3 Feed-specific and total feed-blend indirect carbon impact potentials

As shown in Table 7 and discussed above, the scale of potential HEFA feedstock demand affects the answer to our question about whether feedstocks refiners could use to increase HEFA jet fuel yield could result in relatively more serious indirect carbon impacts.

Palm oil: High volume displacement and international fueling impacts potential

With the highest global availability of any current HEFA feed (Table 7), palm oil is likely to fill in for current uses of other HEFA feeds that growing U.S. feedstock demand for HEFA jet fuel would displace from those uses. This could occur regardless of restrictions on palm oil biofuel, increasing the indirect carbon impacts associated with palm oil expansion. Deforestation in Southeast Asia caused by palm oil expansion has been linked to biofuel demand for soy and rapeseed (canola) oils in the U.S. and Europe at past, much lower, biofuel feedstock demand, as described in section 4.1.1. Its high global availability also increases the likelihood that, despite U.S. policy, palm oil derived HEFA jet fuel could burn in many commercial flights. Jets may fuel this palm biofuel in various nations—including fueling for the return legs of international flights originating in the U.S. Palm oil can thus be considered a high jet fuel yield and relatively high indirect carbon impact HEFA feedstock.

Fish oil: Unique risk at low HEFA feed blend volume

In contrast to palm oil, fish oil is an extremely low availability HEFA feedstock and is unique among HEFA feeds in raising risks to the oceanic carbon sink. Equally important, fish oil has hard-to-replace aquaculture and pharmaceutical uses.[10] At 1.4% of current world supply for HEFA jet fuel demand scenarios in Table 7, fish oil is unlikely to be targeted as a major

HEFA feedstock industry wide. But this also means that existing uses of fish oil that are hard to replace could be fully displaced, driving further fisheries depletion, even if fish oil comprises as little as 1.4% of potential future HEFA feeds. Increased fishing pressure for fish oil is difficult to discount in demand scenarios approaching those shown (*Id.*), as significant upward pressure on lipids prices could impact lipids markets globally. Indeed, world fish oil demand for all uses is projected to grow and continue to be produced in substantial part from whole fish catch.[10] That fish biomass would essentially be extracted from the oceanic carbon sink to emit carbon from land-based uses, however, the larger and more uncertain impact could be on the effectiveness of ocean carbon sequestration via the biological pump (§ 4.1.2).

Available information thus identifies the potential for a future fish oil biofuel impact which may or may not materialize but nevertheless poses significant risk. Fish oil can be considered a high jet fuel yield and relatively high indirect carbon risk HEFA feedstock.

Livestock fat: likely displacement and possible supply growth impacts

While total current livestock fat production could supply only 20% of potential HEFA feedstock demand (Table 7), its relatively high jet fuel yield and relatively low (assumed) indirect carbon impacts could make livestock fat an important fraction of the expanding HEFA feeds mix. This would displace its existing uses, where the fats would likely be replaced by expanded demand for other lipids with relatively higher indirect carbon impacts. High-availability replacements such as palm and soy oils (*Id.*) would likely fill those displaced uses, and both palm and soy oils have relatively high indirect carbon impacts (§ 4.1.1).

Additionally—and notwithstanding the likelihood that livestock protein production would remain the priority—it is possible that the unprecedented growth in livestock fat demand might alter the balance among choices for producing human protein intake in favor of this high jet fuel yield "byproduct" feedstock. This balance is dynamic, as suggested by trends either toward or away from vegetarian diets in various human populations globally, such that this possibility is difficult to discount given the potential for unprecedented livestock fat demand growth. And if HEFA demand were to drive livestock production growth, livestock production is, in fact, a high carbon emission enterprise.[31 49] In view of these likely and possible impacts, livestock fat can be considered a high jet fuel yield and relatively high indirect carbon risk HEFA feedstock.

Feed blends: limited residue supply worsens indirect carbon impacts

Impacts and risks of high jet fuel yield feedstock add to those of feed blends that could be used for HEFA jet fuel, and limited global "residue" feedstock supply heightens these impacts.

HEFA feedstock demand to replace just 18% of 2019 U.S. jet fuel use—half that shown in Table 7—would far exceed current total U.S. production for *all uses* of lipids also tapped for biofuels. One implication of this is the need to consider food and fuel uses of the global lipids supply by other nations. Importantly, at 4.28% of world population, the U.S. per capita share of world production for low impact "residue" feeds from livestock fat and fish oil (Table 7) is less than 0.65 MM t/y, less than 1% of potential U.S. HEFA jet fuel feedstock demand (*Id.*). The limited supply of low impact "residue" feedstocks, in turn, limits alternatives to palm oil or livestock production growth that can feed potential HEFA jet fuel growth. Current major feed alternatives for HEFA jet fuel are limited to soybean oil and other oil crops (*Id.*).

For example, what if U.S. palm biofuel is prohibited, livestock and fish oil production do not grow, and U.S. HEFA "residue" feedstock acquisition grows to eight times its per capita share (5.2 MM t/y)? At half of its minimum potential mid-century growth, HEFA feedstock demand for SAF in the U.S. would be approximately 35.5 MM t/y (Table 7). This 5.2 MM t/y of low-impact feed would meet only 15% of that demand and leave 30.3 MM t/y of that demand unmet. Supplying the 30.3 MM t/y of unmet demand for just half of potential U.S. HEFA jet fuel growth could induce growth of 23.5% in current combined global production for soy and other oil crops, excluding palm oil (*Id.*).

Moreover, the excess U.S. use of limited global residue supply in the example above could have an impact. It could displace the lower-impact HEFA jet fuel feed for SAF fueled in other nations, which could replace residue feeds with higher indirect carbon impact feeds. This would only shift emissions to HEFA jet fueling elsewhere, without providing a global climate benefit.

Thus, even if U.S. policy effectively discourages palm oil biofuel and livestock production does not grow, the potential HEFA jet fuel expansion could be expected to spur an expansion of soybean, corn, and other plant oil crops. Significant indirect carbon impacts have been linked to biofuels demand for soybean and other plant oil feedstocks at past biofuel demand levels that were substantially lower than current and potential future HEFA demand (§ 4.1.1). While this complicates the answer to our question about indirect carbon impacts of feeds to boost HEFA jet fuel yield, importantly, it further informs our answer. It shows that these heightened impacts and risks would add to significant potential impacts of increased total HEFA feedstock demand.

In plausible future SAF implementation scenarios, among the relatively high jet fuel yield feedstocks, palm oil could have relatively serious indirect carbon impacts, and both fish oil and livestock fat could pose relatively serious but currently uncertain indirect carbon impact risks. Those impacts and risks would add to significant potential carbon sink impacts from the blends of feedstocks that could supply HEFA refineries, in which lower impact "residue" feedstocks could supply only a small fraction of total HEFA feedstock growth. Natural limits on total supply for the type of feedstock that HEFA technology can process appear to make replacing any significant portion of current petroleum jet fuel use with this type of biofuel unsustainable.

5. Limitations and suggestions for future work

Two types of data limitations which may affect potential outcomes for SAF were identified in the course of this research. The first involves HEFA technology: interchangeability among other uses of its feedstocks; and its potential future evolution. These HEFA-specific limitations are discussed in Section 5.1 below. The second involves other alternatives to petroleum jet fuel combustion which, though they are outside the scope of this report, warrant mention due to limitations of HEFA technology identified by this research. These are discussed briefly as suggested priorities for future work in Section 5.2.

5.1 HEFA biofuel impact assessment data limitations

5.1.1 Limited cross-feed displacement quantification data

HEFA feedstocks are not "wastes." All of them are lipids, and more specifically, triacylglycerols of fatty acids, which can be converted to functionally similar biological or chemical uses by many biological processes (e.g., digesting food) and chemical processes (e.g., HEFA processing with hydrocracking). Further, these lipids have interchangeable and largely competing uses now, including food for human populations, livestock feeds, pet food, aquaculture feeds, and feedstocks for making soap, wax, lubricants, plastics, natural pigments, cosmetic products and pharmaceutical products.[9] [10] Accordingly, increased biofuel demand for one source of these lipids displaces another existing use of that feedstock, thereby increasing demand and prices for other sources of lipids as well. Indeed, this has occurred, leading to indirect land use impacts that increased carbon emissions associated with biofuels (§ 4.1.1).

For example, if diverting tallow from soap making to HEFA jet fuel forces soap makers to use more palm oil, that jet fuel indirectly emits carbon associated with that extra production of palm oil. The livestock fat biofuel would cause an indirect carbon impact that current biofuel impact accounting practices for "waste" residue feedstocks assume it does not cause.

However, the hypothetical extreme wherein all lipids are 100% fungible, and any increase in HEFA demand for any of these feedstocks would have the same indirect impact by increasing collective demand for all other feeds by the same amount, also seems unrealistic. Some types of lipids, such as those that increase jet fuel production and those people eat directly, could attract relatively higher demand and command relatively higher prices. At present, *how much* demand increase for each lipid source increases indirect carbon impacts associated with cross-feed demand increase has not yet been quantified by universally accepted estimates.

Herein, we take the view that the uses of lipids also tapped for HEFA biofuels are fungible to a significant extent which varies among specific lipids sources and uses. In this view, indirect carbon impacts of future demand for palm oil exceed those of other HEFA feeds which would not be favored by refiners seeking to boost jet fuel production, but by amounts that are not yet fully quantifiable. That quantitative uncertainty results from the data limitations discussed above and explains why this report does not attempt to quantify the feed-specific indirect carbon impacts documented in Chapter 4.

5.1.2 Renewable fuel hydrogen specification error

Splitting water with electricity supplied by solar or wind power—renewable powered electrolysis—produces zero-emission hydrogen fuel. Unfortunately, renewable fuel standards incentivize HEFA fuels even though much of the hydrogen in those hydrocarbons is produced from non-renewable fossil fuels. This is a mistake. This mistake has led to an important limitation in the data for assessing the future potential of HEFA jet fuel.

Hydrogen steam reforming repurposed from crude refining drives the high CI of HEFA refining and its variability among HEFA feedstocks and processing strategies (Chapter 3). Renewable-powered electrolysis could eliminate those steam reforming emissions and result in HEFA refining CI lower than that of petroleum refining.[2] However, the combination of public incentives to refiners for HEFA biofuel, and their private incentives to avoid costs of stranded steam reforming assets they could repurpose and electrolysis they need not build to reap those public incentives, has resulted in universal reliance on steam reforming in HEFA processing. Would the public incentives outweigh the private incentives and cut refining CI if this mistake were corrected, or would the companies decide that another alternative to HEFA jet fuel is more profitable? Since current fuel standards allow them to maximize profits by avoiding the question, there are no observational data to support either potential outcome.

Additionally, if refiners were to replace their steam reformers with renewable-powered electrolysis, energy transition priorities could make that zero-emission hydrogen more valuable for other uses than for biofuel,[2] and biomass feed costs also would weigh on their decisions.[19] Thus, for purposes of the potential impacts assessment herein, and in the absence of observational data on this question, we take the view that assuming HEFA refining without steam reforming emissions would be speculative, and would risk significant underestimation of potential HEFA jet fuel impacts.

5.1.3 Proprietary catalyst development data

Catalysts are crucial in HEFA refining, and although many catalyst data are claimed as trade secrets, their refining benefits are typically advertised, especially if new catalysts improve yields. The search for a new catalyst that can withstand the severe conditions in HEFA reactors and improve processing and yields has been intensive since at least 2013.[50] [51] [52] [53] [54] [55] [56]

From this we can infer two things. First, given the maturity of the hydro-conversion technology crude refiners repurpose for HEFA refining, and that long and intensive search, a newly invented catalyst formulation which improves reported HEFA jet fuel yield significantly appears unlikely. Second, given the incentive, the invention of such a new catalyst is possible. Again, however, many specific catalyst data are not reported publicly. Our findings herein are based on publicly reported, independently verifiable data. This limitation in publicly reported catalysis data thus has the potential to affect our yields analysis.

5.2 Priorities for future work

5.2.1 Cellulose biomass alternatives—what is holding them back?

Cellulosic residue biomass such as cornstalks, currently composted yard cuttings, or sawdust can be used as feedstock by alternative technologies which qualify as SAF.[19] [35] Using this type of feedstock for SAF could lessen or avoid the indirect carbon impacts from excessive HEFA jet fuel demand for limited lipids biomass that are described in Chapter 4. Indeed, economy-wide analyses of the technologies and measures to be deployed over time for climate stabilization suggest prioritizing cellulosic biomass, to the extent that biofuels will be needed in some hard-to-decarbonize sectors.[42] [57] [58] Despite its promise, however, the deployment of cellulosic distillate biofuel has stalled compared with HEFA biofuel. Less clear are the key barriers to its growth, the measures needed to overcome those barriers, and whether or not those measures and the growth of cellulosic jet fuel resulting from them could ensure that SAF goals will be met sustainably. This points to a priority for future work.

5.2.2 Alternatives to burning jet fuel—need and potential to limit climate risks

Even complete replacement of petroleum jet fuel with SAF biofuel combustion would result in ongoing aviation emissions, and would thus rely on additional and separate carbon capture-sequestration to give us a reasonable chance of stabilizing our climate. At the current jet fuel combustion rate the scale of that reliance on “negative emission” technologies, which remain unproven at that scale, is a risky bet. Meanwhile, besides alternative aircraft propulsion systems, which are still in the development stage, there are alternatives to jet fuel combustion which are technically feasible now and can be used individually or in combination.

Technically feasible alternatives to burning jet fuel include electrified high-speed rail, fuel cell powered freight and shipping to replace air cargo, and conservation measures such as virtual business meetings and conserving personal air-miles-traveled for personal visits. While we should note that such travel pattern changes raise social issues, so does climate disruption, and most people who will share our future climate are not frequent fliers. Importantly as well, public acceptance of new travel alternatives is linked to experiencing them. Thus, biofuel limitations, climate risks, and human factors suggest needs to prioritize the development and deployment of alternatives to petroleum jet fuel that do not burn carbon.

5.2.3 Limited safety data record for flying with new fuels

Jet biofuels appear to differ from petroleum jet fuels in their cold flow properties at high altitude, combustion properties, and potential to damage fuel system elastomer material.[19] Those that can be used as SAF have been approved subject to blending limits, which permit SAF to be "dropped-in" to conventional jet fuel up to a maximum of 50% of the blend.[59] All seven types of biofuels approved for SAF are subject to this condition.[59] SAF/petroleum jet fuel blends that do not meet this condition are deemed to present potential safety issues.[59]

However, remarkably limited historical use of SAF (§4.3.1) has resulted in a limited data record for assessing its safety in actual operation. That is important because new hazards which result in dangerous conditions over long periods of operation have repeatedly been discovered only by rigorous post-operational inspection or post-incident investigation, the histories of both industrial and aviation safety oversight show. There is an ongoing need to ensure flight safety risks of biofuels are closely monitored, rigorously investigated, transparently communicated, and proactively addressed by "inherent safety measures"[60] designed to eliminate any specific hazards identified by that future work.

Table 8. Data and methods table for feed-specific estimates.[a]

Fatty acid (FA) in HEFA oil feed			Density (kg/b)*	Oxygen content (wt. %)*	Carbon double bonds	FA-specific hydrogen inputs	
common name	Shorthand	Formula[b]				Deoxygenation[c] (kg H_2/b)	Saturation[d, e] (kg H_2/b)
Caprylic Acid	C8:0	$C_8H_{16}O_2$	145	22.2	0	8.09	0.00
Capric Acid	C10:0	$C_{10}H_{20}O_2$	142	18.6	0	6.65	0.00
Lauric Acid	C12:0	$C_{12}H_{24}O_2$	140	16.0	0	5.63	0.00
Myristic Acid	C14:0	$C_{14}H_{28}O_2$	137	14.0	0	4.84	0.00
Myristoleic Acid	C14:1	$C_{14}H_{26}O_2$	143	14.1	1	5.10	1.27
Pentadecanoic Acid	C15:0	$C_{15}H_{30}O_2$	134	13.2	0	4.45	0.00
Palmitic Acid	C16:0	$C_{16}H_{32}O_2$	135	12.5	0	4.26	0.00
Palmitoleic Acid	C16:1	$C_{16}H_{30}O_2$	142	12.6	1	4.50	1.13
Margaric Acid	C17:0	$C_{17}H_{34}O_2$	136	11.8	0	4.04	0.00
Stearic Acid	C18:0	$C_{18}H_{36}O_2$	134	11.2	0	3.79	0.00
Oleic Acid	C18:1	$C_{18}H_{34}O_2$	141	11.3	1	4.04	1.01
Linoleic Acid	C18:2	$C_{18}H_{32}O_2$	143	11.4	2	4.12	2.06
Linolenic Acid	C18:3	$C_{18}H_{30}O_2$	145	11.5	3	4.21	3.16
Stearidonic Acid	C18:4	$C_{18}H_{28}O_2$	148	11.6	4	4.33	4.33
Arachidic Acid	C20:0	$C_{20}H_{40}O_2$	131	10.2	0	3.38	0.00
Gondoic Acid	C20:1	$C_{20}H_{38}O_2$	140	10.3	1	3.65	0.91
Eicosadienoic Acid	C20:2	$C_{20}H_{36}O_2$	144	10.4	2	3.76	1.88
Homo-*y*-linoleic Acid	C20:3	$C_{20}H_{34}O_2$	146	10.4	3	3.84	2.88
Arachidonic Acid	C20:4	$C_{20}H_{32}O_2$	147	10.5	4	3.88	3.88
Eicosapentaenoic Acid	C20:5	$C_{20}H_{30}O_2$	150	10.6	5	4.00	5.00
Henicosanoic Acid	C21:0	$C_{21}H_{42}O_2$	142	9.80	0	3.50	0.00
Heneicosapentaenoic Acid	C21:5	$C_{21}H_{32}O_2$	149	10.1	5	3.79	4.74
Behenic Acid	C22:0	$C_{22}H_{44}O_2$	131	9.39	0	3.09	0.00
Erucic Acid	C22:1	$C_{22}H_{42}O_2$	137	9.45	1	3.26	0.81
Docosadienoic Acid	C22:2	$C_{22}H_{40}O_2$	143	9.51	2	3.43	1.71
Docosatetraenoic Acid	C22:4	$C_{22}H_{36}O_2$	151	9.62	4	3.66	3.66
Docosapentaenoic Acid	C22:5	$C_{22}H_{34}O_2$	148	9.68	5	3.62	4.52
Docosahexaenoic Acid	C22:6	$C_{22}H_{32}O_2$	150	9.74	6	3.68	5.52
Lignoceric Acid	C24:0	$C_{24}H_{48}O_2$	140	8.68	0	3.06	0.00
Tetracosenoic Acid	C24:1	$C_{24}H_{46}O_2$	141	8.73	1	3.11	0.78

*** b (barrel):** 42 U.S. gallons; **wt. %:** weight percent on fatty acid

a. See notes to this table for feedstock-specific data sources.

b. Formula symbols; carbon: C (12.011 g/mol); hydrogen: H (1.00794 g/mol); oxygen: O (15.995 g/mol).

c. Deoxygenation: Hydrogen consumed to remove and replace oxygen and propane knuckle-fatty acid bonds.

b. Saturation: Hydrogen consumed to saturate carbon double bonds in HEFA processing.

e. Additional process hydrogen consumption in side-reaction cracking, solubilization, scrubbing **and** purge losses not shown.

Continued next page

Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Selected plant oils, livestock fats and fish oils						
Fatty acid	FA	Median of sample analysis profile data reported based on C18:2, in wt. % [a]						
Common name	Shorthand	Soybean	Corn	Canola	Cottonseed	Palm	Tallow	Lard
Caprylic	C8:0					0.186		
Capric	C10:0					0.324		0.070
Lauric	C12:0					2.284	1.010	
Myristic	C14:0	0.100		0.040	0.860	1.108	3.384	1.280
Myristoleic	C14:1							
Pentadecanoic	C15:0							
Palmitic	C16:0	11.000	12.860	4.248	23.600	41.480	24.495	25.000
Palmitoleic	C16:1	0.100	0.100	0.287	0.360	0.167	4.040	3.000
Margaric	C17:0			0.069		0.059	2.020	0.330
Stearic	C18:0	4.000	1.760	1.752	2.400	4.186	17.525	12.540
Oleic	C18:1	23.400	26.950	60.752	17.740	39.706	42.121	44.000
Linoleic	C18:2	53.200	55.880	20.713	54.420	9.902	3.293	11.000
Linolenic	C18:3	7.800	1.260	8.980	0.600	0.196	1.818	0.550
Stearidonic	C18:4							
Arachidic	C20:0	0.300	0.390	0.713	0.220	0.304	0.313	0.190
Gondoic	C20:1		0.280	1.277	0.070	0.078	0.081	0.800
Eicosadienoic	C20:2							0.740
Homo-γ-linoleic	C20:3							0.110
Arachidonic	C20:4							0.300
Eicosapentaenoic	C20:5							
Henicosanoic	C21:0							
Heneicosapentaenoic	C21:5							
Behenic	C22:0	0.100	0.120	0.307	0.110	0.039		
Erucic	C22:1			0.594				
Docosadienoic	C22:2							
Docosatetraenoic	C22:4		0.120					
Docosapentaenoic	C22:5		0.180					
Docosahexaenoic	C22:6							
Lignoceric	C24:0			0.099		0.049		
Tetracosenoic	C24:1							
Whole feed FAs	O_2 wt. %	11.50	11.50	11.35	11.71	11.99	11.80	11.66
	Deoxygenation (kg H_2 /b)	4.11	4.11	4.06	4.14	4.19	4.11	4.13
	Saturation (kg H_2 /b)	1.58	1.48	1.35	1.32	0.61	0.60	0.76
C8–C16 Fraction	(vol. %)	11.71	13.56	4.78	25.67	46.47	33.34	30.00
	Deoxygenation (kg H_2 /b)	4.27	4.26	4.28	4.28	4.38	4.39	4.32
	Saturation (kg H_2 /b)	0.01	0.01	0.07	0.02	0.004	0.14	0.12
C15–C18 Fraction	(vol. %)	99.46	98.88	96.85	98.70	95.63	95.18	96.53
	Deoxygenation (kg H_2 /b)	4.11	4.11	4.08	4.13	4.13	4.08	4.09
	Saturation (kg H_2 /b)	1.59	1.48	1.37	1.34	0.64	0.63	0.75
> C18 Fraction	(vol. %)	0.43	1.12	3.11	0.42	0.49	0.41	2.10
	Deoxygenation (kg H_2 /b)	3.31	3.49	3.43	3.35	3.37	3.43	3.70
	Saturation (kg H_2 /b)	0.00	1.38	0.55	0.16	0.15	0.19	1.68

Continued next page

Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Selected plant oils, livestock fats and fish oils, *continued*					
Fatty acid	FA	Median of sample analysis profile data reported based on C18:2, wt. % [a]					
Common name	Shorthand	Poultry	Anchovy	Herring	Menhaden	Salmon	Tuna
Caprylic	C8:0						
Capric	C10:0						
Lauric	C12:0						
Myristic	C14:0	0.618	6.636	7.755	8.602	6.044	5.903
Myristoleic	C14:1	0.206					0.447
Pentadecanoic	C15:0		0.701	0.408	0.538	0.769	0.359
Palmitic	C16:0	24.206	16.355	15.306	21.505	17.143	17.670
Palmitoleic	C16:1	6.951	7.757	8.469	10.108	2.198	5.961
Margaric	C17:0	0.108	0.935	0.510	1.075	1.099	0.650
Stearic	C18:0	5.814	3.738	2.143	3.333	2.637	4.155
Oleic	C18:1	42.157	12.150	17.245	15.000	15.385	16.078
Linoleic	C18:2	18.137	1.636	1.633	2.151	1.648	1.068
Linolenic	C18:3	0.657	5.607	0.612	1.398	4.451	1.748
Stearidonic	C18:4		2.336	2.551	3.333	3.077	
Arachidic	C20:0		0.841		0.323	0.385	0.408
Gondoic	C20:1	0.392	3.738	11.224	1.075	1.978	4.922
Eicosadienoic	C20:2						0.272
Homo-*γ*-linoleic	C20:3						3.437
Arachidonic	C20:4		2.103	0.408	1.720	2.967	0.184
Eicosapentaenoic	C20:5		14.486	8.776	13.441	12.637	9.282
Henicosanoic	C21:0						
Heneicosapentaenoic	C21:5		1.869		0.806	2.582	
Behenic	C22:0	0.118					0.078
Erucic	C22:1	0.098	3.224	15.102	0.645	6.099	0.311
Docosadienoic	C22:2						
Docosatetraenoic	C22:4						
Docosapentaenoic	C22:5		1.869	1.327	2.258	3.077	5.252
Docosahexaenoic	C22:6		14.252	6.327	12.366	15.385	20.670
Lignoceric	C24:0	0.098					0.845
Tetracosenoic	C24:1	0.363					0.583
Whole feed FAs	O_2 wt. %	11.70	11.33	11.22	11.53	11.11	11.20
	Deoxygenation (kg H_2 /b)	4.13	4.06	3.99	4.13	4.01	4.01
	Saturation (kg H_2 /b)	0.91	2.34	1.52	2.08	2.42	2.31
C8–C16 Fraction	(vol. %)	32.69	32.56	32.73	42.26	27.48	31.46
	Deoxygenation (kg H_2 /b)	4.33	4.45	4.47	4.45	4.42	4.44
	Saturation (kg H_2 /b)	0.25	0.28	0.30	0.28	0.09	0.24
C15–C18 Fraction	(vol. %)	98.09	52.19	49.34	59.81	49.73	48.92
	Deoxygenation (kg H_2 /b)	4.13	4.20	4.20	4.21	4.17	4.17
	Saturation (kg H_2 /b)	0.92	1.02	0.89	0.85	1.01	0.64
> C18 Fraction	(vol. %)	1.07	40.93	42.68	31.25	43.96	44.52
	Deoxygenation (kg H_2 /b)	3.31	3.76	3.59	3.81	3.72	3.72
	Saturation (kg H_2 /b)	0.67	4.31	2.52	4.83	4.27	4.34

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Used cooking oil (UCO) variability			
Fatty acid	FA	Percentiles on C18:2, in wt. % *			
Common name	Shorthand	10th Percentile	25th Percentile	75th Percentile	90th Percentile
Caprylic	C8:0				
Capric	C10:0				
Lauric	C12:0				
Myristic	C14:0	0.909	2.479	1.735	
Myristoleic	C14:1				
Pentadecanoic	C15:0				
Palmitic	C16:0	20.606	20.248	16.412	12.420
Palmitoleic	C16:1	4.646		1.735	
Margaric	C17:0				
Stearic	C18:0	4.848	12.810	5.235	5.760
Oleic	C18:1	53.434	38.017	29.843	26.930
Linoleic	C18:2	13.636	23.967	41.324	49.600
Linolenic	C18:3	0.808	2.066	3.500	4.930
Stearidonic	C18:4				
Arachidic	C20:0	0.121			0.750
Gondoic	C20:1	0.848			
Eicosadienoic	C20:2				
Homo-y-linoleic	C20:3				
Arachidonic	C20:4				
Eicosapentaenoic	C20:5				
Henicosanoic	C21:0				
Heneicosapentaenoic	C21:5				
Behenic	C22:0	0.030			
Erucic	C22:1	0.071			
Docosadienoic	C22:2				
Docosatetraenoic	C22:4				
Docosapentaenoic	C22:5				
Docosahexaenoic	C22:6				
Lignoceric	C24:0	0.040			
Tetracosenoic	C24:1				
Whole feed FAs	O_2 wt. %	11.64	11.59	11.59	11.55
	Deoxygenation (kg H_2 /b)	4.11	4.09	4.12	4.10
	Saturation (kg H_2 /b)	0.91	0.95	1.29	1.44
C8–C16 Fraction	(vol. %)	26.81	23.49	20.61	12.90
	Deoxygenation (kg H_2 /b)	4.32	4.32	4.33	4.26
	Saturation (kg H_2 /b)	0.20	0.00	0.10	0.09
C15–C18 Fraction	(vol. %)	97.95	97.46	98.21	99.19
	Deoxygenation (kg H_2 /b)	4.11	4.08	4.11	4.10
	Saturation (kg H_2 /b)	0.92	0.97	1.31	1.46
> C18 Fraction	(vol. %)	1.12	0.00	0.00	0.81
	Deoxygenation (kg H_2 /b)	3.56	0.00	0.00	3.38
	Saturation (kg H_2 /b)	0.75	0.00	0.00	0.00

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Data for feedstock fractions outside the jet fuel range (> C16)

Feedstock		Soybean	Corn	Canola	Cottonseed	Palm	Tallow	Lard
> C16 Fraction	(vol. %)	88.29	86.44	95.22	74.33	53.53	66.66	70.00
Deoxygenation (kg H_2 /b)		4.09	4.08	4.05	4.09	4.03	3.98	4.00
Saturation (kg H_2 /b)		1.78	1.70	1.41	1.75	1.12	0.82	1.03

Feedstock		Poultry	Anchovy	Herring	Menhaden	Salmon	Tuna
> C16 Fraction	(vol. %)	67.31	67.44	67.27	57.74	72.52	68.54
Deoxygenation (kg H_2 /b)		4.03	3.88	3.76	3.92	3.86	3.82
Saturation (kg H_2 /b)		1.22	3.29	2.10	3.33	3.25	3.21

Feedstock		Used Cooking Oil (UCO			
Percentile on C18:2 in wt.%		10th	25th	75th	90th
> C16 Fraction	(vol. %)	73.19	76.51	79.39	87.10
Deoxygenation (kg H_2 /b)		4.03	4.03	4.07	4.07
Saturation (kg H_2 /b)		1.16	1.23	1.58	1.65

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Process hydrogen consumption by feedstock and processing strategy (kg/b feed)

HDO Δ ONLY	Jet range (C8–C16)			Diesel range (C15–C18)			Longer chains (> C18)		
(No-IHC)	(vol.%)	Ox (kg/b)	Sat (kg/b)	(vol.%)	Ox (kg/b)	Sat (kg/b)	(vol.%)	Ox (kg/b)	Sat (kg/b)
High jet/high diesel									
Palm oil	46.47	4.38	0.004	95.63	4.13	0.64	0.49	3.37	0.15
Tallow fat	33.34	4.39	0.14	95.18	4.08	0.63	0.41	3.43	0.19
Poultry fat	32.69	4.33	0.25	98.09	4.13	0.92	1.07	3.31	0.67
Lard fat	30.00	4.32	0.12	96.53	4.09	0.75	2.10	3.70	1.68
UCO 10th P.	26.81	4.32	0.20	97.95	4.11	0.92	1.12	3.56	0.75
Cottonseed oil	25.67	4.28	0.02	98.70	4.13	1.34	0.42	3.35	0.16
High jet/low diesel									
Menhaden oil	42.26	4.45	0.28	59.81	4.21	0.85	31.25	3.81	4.83
Herring oil	32.73	4.47	0.30	49.34	4.20	0.89	42.68	3.59	2.52
Anchovy oil	32.56	4.45	0.28	52.19	4.20	1.02	40.93	3.76	4.31
Tuna oil	31.46	4.44	0.24	48.92	4.17	0.64	44.52	3.72	4.34
Salmon oil	27.48	4.42	0.09	49.73	4.17	1.01	43.96	3.72	4.27
Low jet/high diesel									
Corn (DCO) oil	13.56	4.26	0.01	98.88	4.11	1.48	1.12	3.49	1.38
UCO 90th P.	12.90	4.26	0.09	99.19	4.10	1.46	0.81	3.38	0.00
Soybean oil	11.71	4.27	0.01	99.46	4.11	1.59	0.43	3.31	0.00
Canola oil	4.78	4.28	0.07	96.85	4.08	1.37	3.11	3.43	0.55

HDO & INTENTIONAL	HDO Δ (Ox + Sat)			Intentional Hydrocracking (IHC)			Jet target H2 Δ by processing case		
HYDROCRACKING	Jet rg.	Diesel rg.	> C18	Selective-IHC		Isom IHC	No-IHC	Select-IHC	Isom-IHC
vol. weighted data	(kg/b)	(kg/b)	(kg/b)	(b fraction)	(kg/b)	(kg/b)	(kg/b)	(kg/b)	(kg/b)
High jet/high diesel	—fractions do not add—			> C16	(factor)*	(factor)*	whole feed	whole feed	whole feed
Palm oil	2.04	4.57	0.02	0.535	1.87	1.80	4.79	5.79	6.60
Tallow fat	1.51	4.47	0.01	0.667	2.10	1.99	4.71	6.11	6.70
Poultry fat	1.50	4.95	0.04	0.673	1.85	1.82	5.03	6.28	6.85
Lard fat	1.33	4.67	0.11	0.700	1.84	1.81	4.85	6.13	6.65
UCO 10th P.	1.21	4.92	0.05	0.732	1.85	1.82	5.01	6.37	6.83
Cottonseed oil	1.10	5.40	0.01	0.743	1.88	1.84	5.44	6.84	7.28
High jet/low diesel									
Menhaden oil	2.00	3.03	2.70	0.577	1.93	1.84	6.18	7.30	8.02
Herring oil	1.56	2.51	2.61	0.673	1.87	1.83	5.50	6.76	7.33
Anchovy oil	1.54	2.72	3.30	0.674	1.93	1.86	6.37	7.67	8.23
Tuna oil	1.47	2.35	3.59	0.685	1.94	1.87	6.29	7.62	8.16
Salmon oil	1.24	2.57	3.51	0.725	1.91	1.85	6.40	7.78	8.25
Low jet/high diesel									
Corn (DCO) oil	0.58	5.53	0.05	0.864	1.86	1.84	5.58	7.19	7.42
UCO 90th P.	0.56	5.51	0.03	0.871	1.87	1.84	5.55	7.17	7.39
Soybean oil	0.50	5.67	0.01	0.883	1.86	1.84	5.68	7.33	7.52
Canola oil	0.21	5.28	0.12	0.952	1.85	1.84	5.40	7.16	7.24

Note: H_2 inputs shown exclude side-reaction cracking, solubilization, scrubbing and purge gas losses.

* IHC H_2 consumption at 1.3 wt. % feed (Pearlson et al.), in kg/b IHC input.

See table notes next page

Explanatory notes and data sources for Table 8.

Feeds shown have been processed in the U.S. except for palm oil, which is included because it is affected indirectly by U.S. feedstock demand and could be processed in the future, possibly in the U.S. and more likely for fueling international flights in various nations. Median values shown for feed composition were based on the median of the data cluster centered by the median value for C18:2 (linoleic acid) for each individual whole feed. Blend data were not available for used cooking oil (UCO), except in the form of variability among UCO samples collected, which showed UCO to be uniquely variable in terms of HEFA processing characteristics. The table reports UCO data as percentiles of the UCO sample distribution.

Data for feedstock composition were taken from the following sources:

Soybean oil[54 55 61 62 63 64 65 66]

Corn oil (distillers corn oil)[54 61 63 65 67 68 69 70]

Canola oil (includes rapeseed oil)[54 55 61–65 67 69 71 72 73]

Cottonseed oil[54 55 63 65 67]

Palm oil[54 55 62–65 67 68 74]

Tallow (predominantly beef fat)[54 64 69 71 75 76 77 78 79]

Lard (pork fat)[68 76 79]

Poultry fat[54 69 76 79 80]

Anchovy[81]

Herring[82 83]

Menhaden[54 81 82]

Salmon[81 83]

Tuna[81 84 85]

Used cooking oil (UCO)[74 78 86 87 88 89 90 91 92]

Hydrogen consumption to deoxygenate and saturate feeds was calculated from fatty acids composition data for each feed and feed fraction shown. Note that O_2 wt.% data shown are for fatty acids excluding the triacylglycerol propane knuckle; O_2 molar data rather than wt.% data were used to calculate hydrogen demand. Added hydrogen consumption by intentional hydrocracking was calculated at 1.3 wt.% on feed from Pearlson et al.[3] and the inputs to each intentional hydrocracking strategy type (Chapter 1), which were taken from the data in Table 8 and used as shown at the end of Table 8 above. Selective-IHC input volume differs among feeds, as described in chapters 1–3.

Hydrogen losses to side-reaction cracking, solubilization in process fluids, and scrubbing and purging of process gases (not shown in Table 8) result in additional hydrogen production, and thus steam reforming emissions. This was addressed for the steam reforming emissions illustrated in Chart 1 by adding 2.5 kg CO_2/b feed to the emissions shown in Table 5, based on steam reforming emissions of 9.82 g CO_2/g H_2 (Chapter 3) and assumed additional hydrogen production of 0.26 kg H_2/b feed. This is a conservative assumption for hydrogen which reflects a lower bound estimate for those losses. Hydrogen losses through side-reaction cracking, solubilization, scrubbing and purging combined would likely range from 102 SCFB (0.26 kg/b) to more than 196 SCFB (0.5 kg/b),[2] based on analysis of data from a range of published HEFA processing and petroleum processing hydro-conversion process analyses and professional judgment.[2 4 50–56 93 94 95 96]

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APPENDIX C

Karras, G., *Technical Report in Support of Comments* (Karras, 2021c)

Technical Report by Greg Karras
G. Karras Consulting (Community Energy reSource)[1]
16 December 2021

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.

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[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. See 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 Available evidence indicates that the project would use HEFA technology.

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] See 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

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[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

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[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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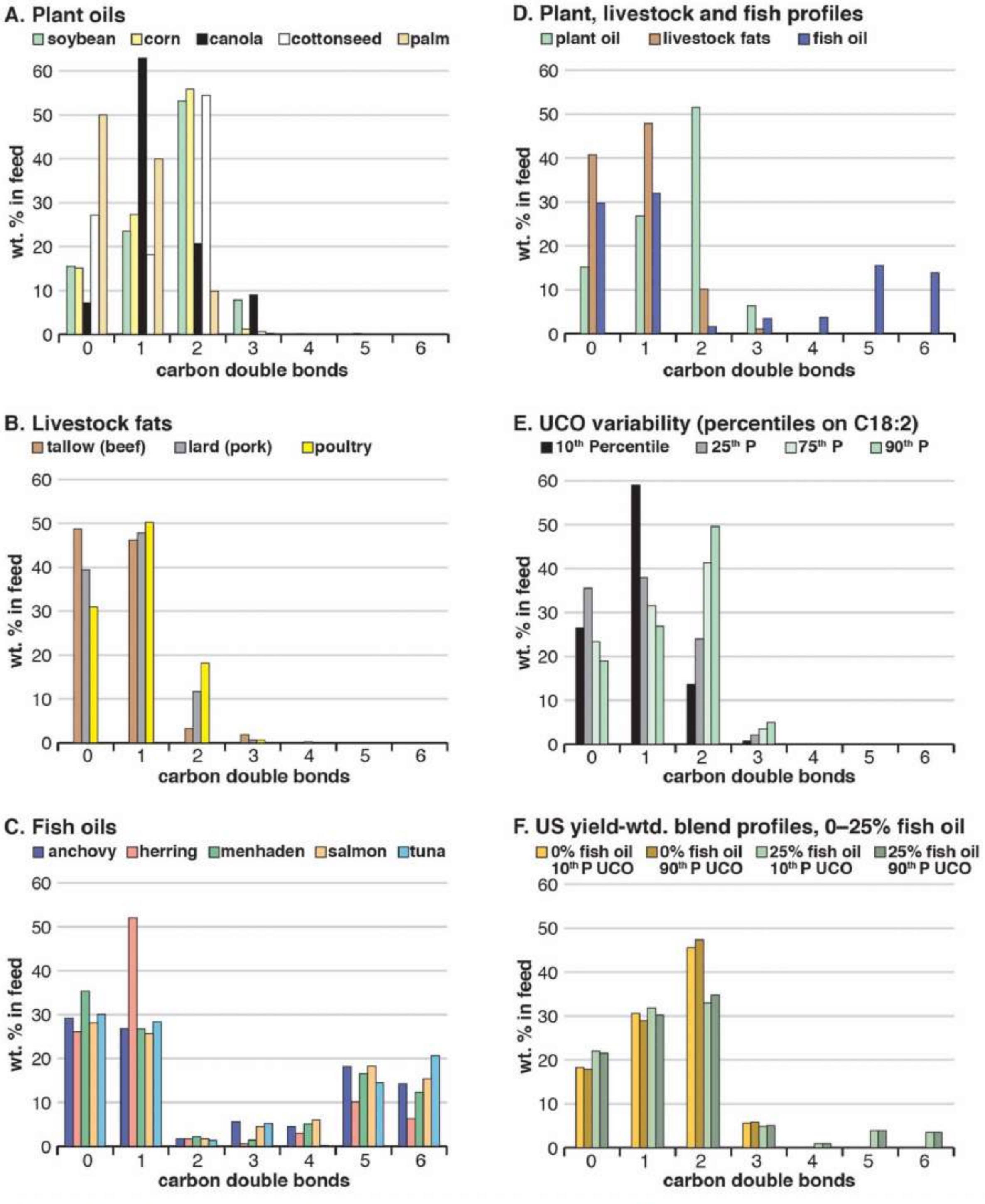
[38] See Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.

[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.

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[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

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[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 The Nustar Shore Terminals biofuel feedstock import conversion

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.

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[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 The component to debottleneck hydrogen-limited refining capacity

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).

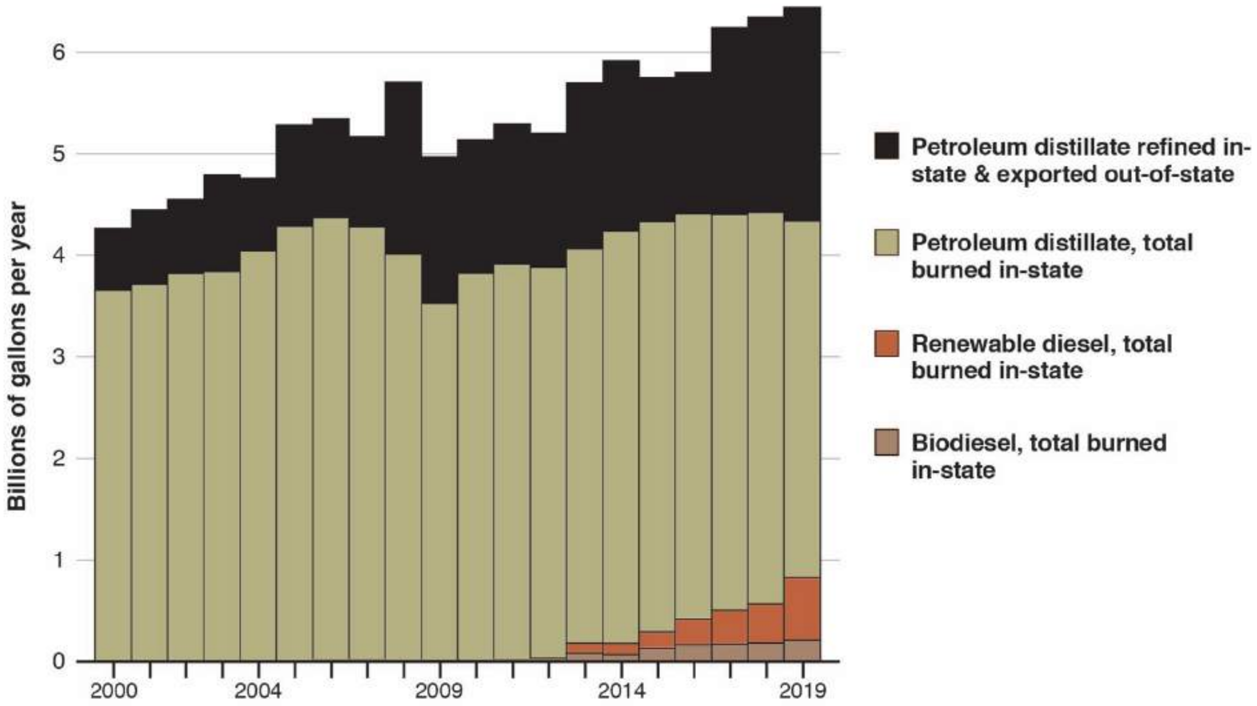
[76] CCR §§ 38505 (j), 38562 (b) (8).

[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. *See* 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] *See* 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).

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[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. See 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 in 2021	Pre-COVID range (2012–2019)			Comparison of 2021 data with the same month in 2012–2019
		Minimum	Median	Maximum	
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.

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[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] See 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	Pre-COVID range (2010–2019)			Comparison of 2021 data with
	in 2021	Minimum	Median	Maximum	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

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[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.

	Capacity Utilized	Pre-COVID range for same month in 2010–2019		
Month	**in 2021**	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.

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[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. See 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 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

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

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 The DEIR did not identify significant hydrogen-related process hazard impacts that could result from the project

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

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

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

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. *See 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. *See* 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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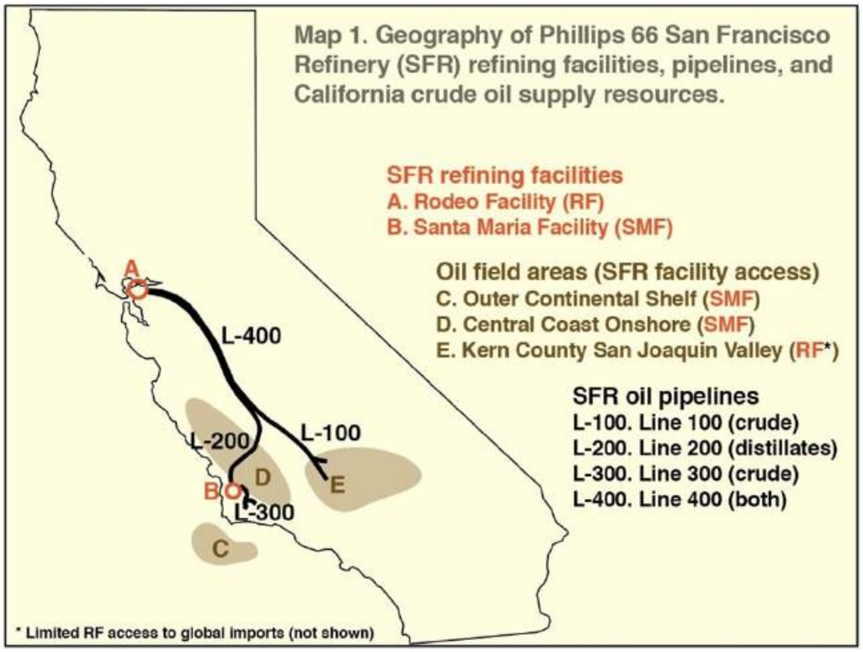
[155] The San Francisco Refining Complex (SFC) includes its Rodeo Refining Facility (RF), Santa Maria Refining Facility (SMF) and pipelines that feed crude to the SMF and crude blended with semi-refined oil to the RF.

[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.



Map 1. Geography of Phillips 66 San Francisco Refinery (SFR) refining facilities, pipelines, and California crude oil supply resources.

* Limited RF access to global imports (not shown)

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. *See* 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. See 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 Phillips 66 action to expand marine vessel imports warned of refinery curtailment risk

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

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[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 Federal crude extraction data pertinent to the project baseline confirm a sharp decline in the major historic source of crude refined by the SMF

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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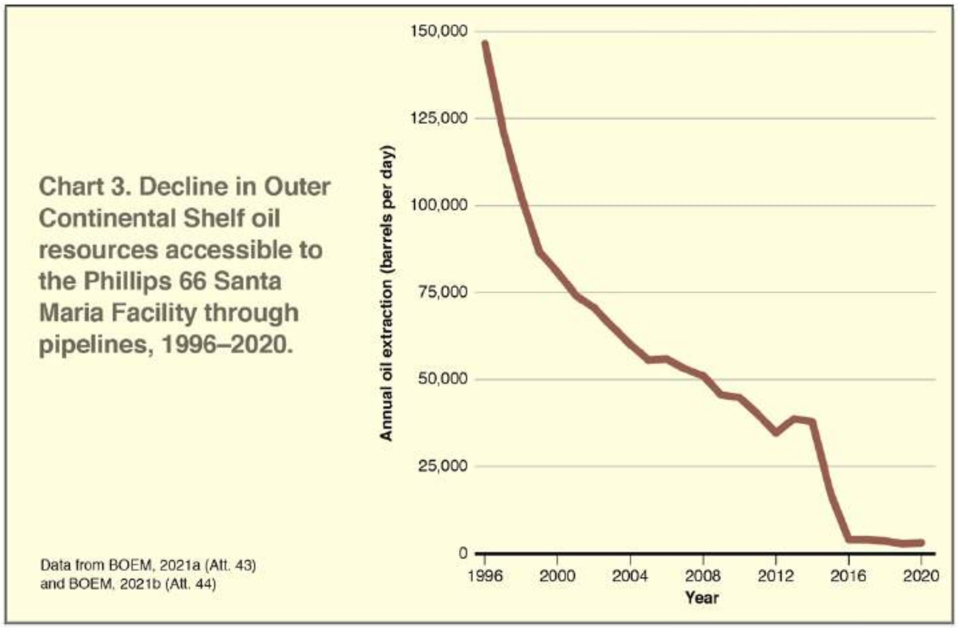
[177] SBC, 2021. *ExxonMobil Interim Trucking for SYU Phased Restart Project Status, Description, Timeline;* Santa Barbara County Department of Planning & Development. Website page accessed 18 November 2021. Appended hereto as Attachment 42.

[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.



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 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

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]

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[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. *See* 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.

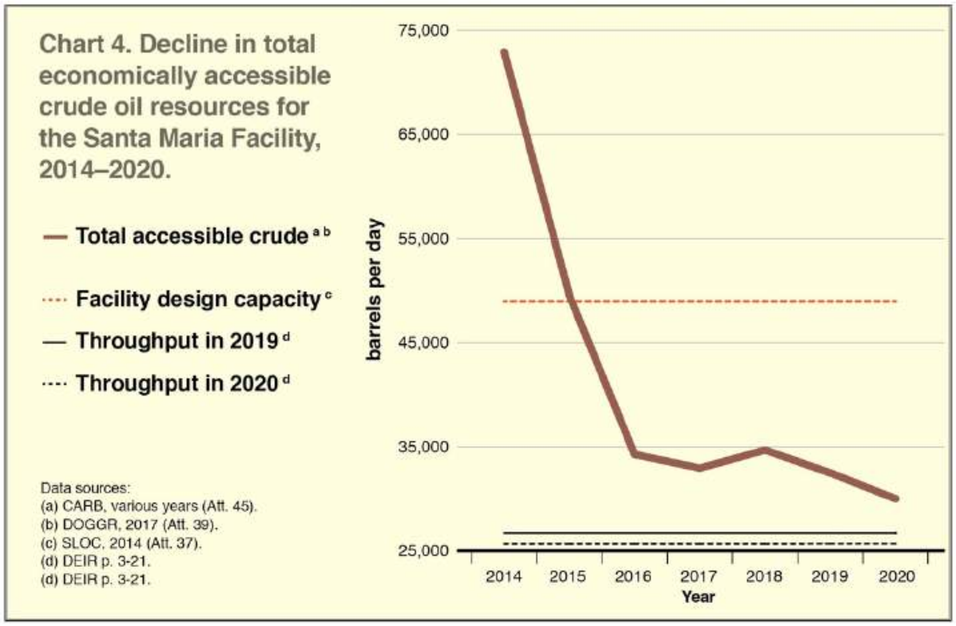
Chart 4. Decline in total economically accessible crude oil resources for the Santa Maria Facility, 2014–2020.

Data sources:
(a) CARB, various years (Att. 45).
(b) DOGGR, 2017 (Att. 39).
(c) SLOC, 2014 (Att. 37).
(d) DEIR p. 3-21.
(d) DEIR p. 3-21.

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.

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[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.

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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.

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Attachment C

May 2021 Application for Authority to Construct and Title V Operating Permit Revision for Rodeo Renewed Project

Prepared for:
Phillips 66
Rodeo, California

Prepared By:
Ramboll US Consulting
San Francisco, California

Date
May 2021

APPLICATION FOR AUTHORITY TO CONSTRUCT PERMIT AND TITLE V OPERATING PERMIT REVISION FOR RODEO RENEWED PROJECT

PHILLIPS 66 COMPANY SAN FRANCISCO REFINERY (DISTRICT PLANT NO. 21359 AND TITLE V FACILITY # A0016)

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IN-LINE FIGURES

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ACRONYMS AND ABBREVIATIONS

APCO	Air Pollution Control Officer
ATC	Authority to Construct
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BBL	barrels
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CIP	Clean In Place
CO	Carbon Monoxide
DAF	Dissolved Air Floatation Unit
EIR	Environmental Impact Report
EPA	Environmental Protection Agency
FCU	Fluid Coking Unit
FCCU	Fluidized Catalytic Cracking Unit
FG	Fuel Gas
FOG	Fat Oil & Grease
GHG	Greenhouse Gas
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HI	Hazard Index
HRA	Health Risk Assessment
IBP	Initial Boiling Point
kPA	kilopascals
lb	pound
LDAR	Leak Detection and Repair
MEIR	Maximum Exposed Individual Resident
MEIW	Maximum Exposed Individual Worker
MMBtu	million British thermal unit
MW	megawatts
NAICS	North American Industrial Classification Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants

N_2	Nitrogen Gas
NH_3	Ammonia
NO_x	Nitrogen Oxides
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
NSR	New Source Review
OEHHA	Office of Environmental Health Hazard Assessment
OGV	Ocean Going Vessel
OLD	Organic Liquids Distribution
$PM_{2.5}$	Particulate Matter less than 2.5 microns
PM_{10}	Particulate Matter less than 10 microns
POC	Precursor Organic Compounds
ppm	Parts Per Million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
PTU	Feed Pretreatment Unit
RACT	Reasonably Available Control Technology
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOCMI	Synthetic Organic Chemicals Manufacturing Industry
STU	Sulfur Treatment Unit
TAC	Toxic Air Contaminant
TBACT	Best Available Control Technology for Toxics
TVP	True Vapor Pressure
ULSD	Ultra-Low Sulfur Diesel
USEPA	United States Environmental Protection Agency
VHAP	Volatile Hazardous Air Pollutant
VOC	Volatile Organic Compounds
WSAC	Wet Surface Air Cooler
WWTP	Wastewater Treatment Plant

1. INTRODUCTION

The Phillips 66 Company (“Phillips 66”) San Francisco Refinery (“Refinery”) is located in the community of Rodeo in Contra Costa County, CA. The proposed Rodeo Renewed Project (“the Project”) will convert the existing petroleum processing equipment and infrastructure into a facility that will process non-hazardous renewable feedstocks into renewable diesel fuel, renewable components of other transportation fuels, and renewable fuel gas. The processing of crude oil will be discontinued. The repurposed plant will be referred to as the Rodeo Facility or Facility hereafter. This application is for an Authority to Construct (ATC) permit and a Title V Permit Revision for the Project.

The Project will also require a land use permit from Contra Costa County. Approval of the land use permit will require compliance with the California Environmental Quality Act (CEQA), including preparation of an Environmental Impact Report (EIR).

Construction is currently scheduled to begin as early as the first quarter of 2022 when all required permits are received. Startup would occur after the completion of construction, which is estimated to take approximately 21 months.

The Refinery currently has the capacity to produce approximately 120,000 barrels of petroleum-based products per day (bbl/day on a 12-month rolling average basis). Once the Project is operational, no petroleum crude oil would be processed at the Rodeo Facility. After the Project, the Rodeo Facility will produce up to 67,000 bbl/day, on a 12-month rolling average basis, of renewable fuels. To maintain current facility capacity to supply regional market demand for transportation fuels, including renewable and conventional fuels, the Rodeo Facility could receive, blend, and ship up to 40,000 bbl/day, on a 12-month rolling average, of gasoline and gasoline blend stocks.

Phillips 66 is planning to utilize as much existing equipment and infrastructure as possible for receiving, transferring, and storing future feedstocks and products. The renewable feedstocks may include, but are not limited to soybean oil, tallow, used cooking oil, inedible corn oil, canola oil, fats, oils, and grease (FOG) and other vegetable-based oils.

This application contains the existing and proposed process descriptions. An applicability determination is also included to evaluate whether existing sources affected by the Project should be considered altered or modified sources. An analysis of New Source Review (NSR) requirements applicable to new and modified sources is presented. The Project triggers Best Available Control Technology (BACT) for fugitive components at a new unit. The Project will result in an overall decrease in annual potential to emit (PTE), so emissions offsets are not required. The Project will not qualify either as a Federal Major Modification (as defined in BAAQMD Rule 2-1-234) or as a Prevention of Significant Deterioration (PSD) Project (as defined in BAAQMD Rule 2-2-224). Applicability of these regulations and supporting emissions calculations are included in this application.

Current and future regulatory applicability is assessed in this application. This includes BAAQMD regulations and federal New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAPs). Throughout this application text, tables referenced as **Table X-X** refer to in-line tables. Tables referenced as **Table X** refer to a table directly following the text.

This application is divided into 8 sections as follows:

Section 1.0 – Introduction: Presents the Project and overview of the application and outlines the document organization.

Section 2.0 – Process Description: Describes the Project and planned changes to process units.

Section 3.0 – Air Permit Applicability: Describes the sources included in the Project.

Section 4.0 – Applicable BAAQMD Regulations: Describes the applicable BAAQMD requirements for the Project.

Section 5.0 – Applicable Federal Regulations: Describes the applicable federal requirements for the Project.

Section 6.0 – Best Available Control Technology: Describes BACT applicability and applicable BACT analyses.

Section 7.0 – Reasonably Available Control Technology: Describes RACT applicability and applicable RACT analyses.

Section 8.0 – Federal Major Modification Applicability: Describes the federal major modification applicability analysis.

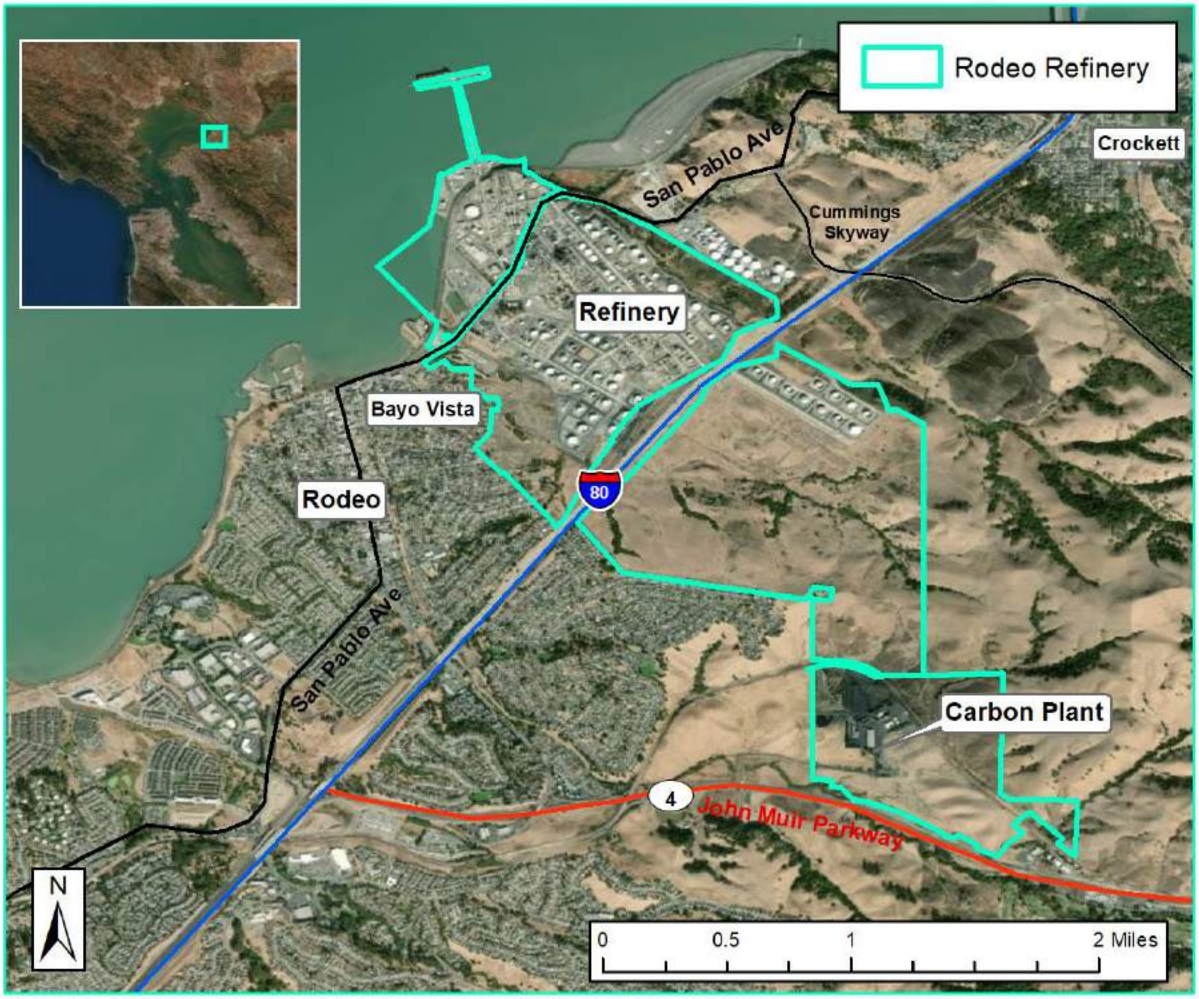
Appendices:

Appendix A - BAAQMD Application Forms
Appendix B - Emissions – includes emission calculation methodology
Appendix C - Permit Fee Calculations

2. PROCESS DESCRIPTION

This section describes the current operation at the Rodeo Refinery and the proposed operation at the Rodeo Facility after the Project. The location of the Facility is shown in **Figure 2-1** below.

Figure 2-1. Refinery Location and Vicinity



Service Layer Credits: Source: Esri, Maxar, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AeroGRID, IGN, and the GIS User Community

2.1 Existing Conditions and Facilities

The Rodeo Refinery consists of process, storage, and support facilities (**Figure 2-2**) that produce a variety of petroleum-based products (mainly fuels) and by-products from petroleum crude oil and other petroleum-based feedstocks (such as pressure distillate and gas oils). Under existing conditions, crude oil is brought into the Rodeo Refinery via pipeline from elsewhere in California and via tanker vessels from domestic and foreign sources. Other feedstocks are required in the refining process; some are transported by pipeline from the Santa Maria Site, by tanker vessel, and by truck (small quantities of transmix), while others, such as hydrogen, are produced on-site or nearby. Tanker and barge vessels dock at the

Rodeo Refinery Marine Terminal, located at the northern tip of the Rodeo Site, which is connected to the Rodeo Refinery by pipelines. Crude oil and feedstocks are stored in tank farms within the Refinery until they are transferred to the refining process. The Refinery also produces process steam, fuel gas, and electricity for use in the refining process, and purchases electricity, water, and natural gas. The Refinery has the capacity to produce approximately 120,000 barrels of petroleum-based products per day (5.04 million gallons per day) via the processes shown in **Figure 2-2**.

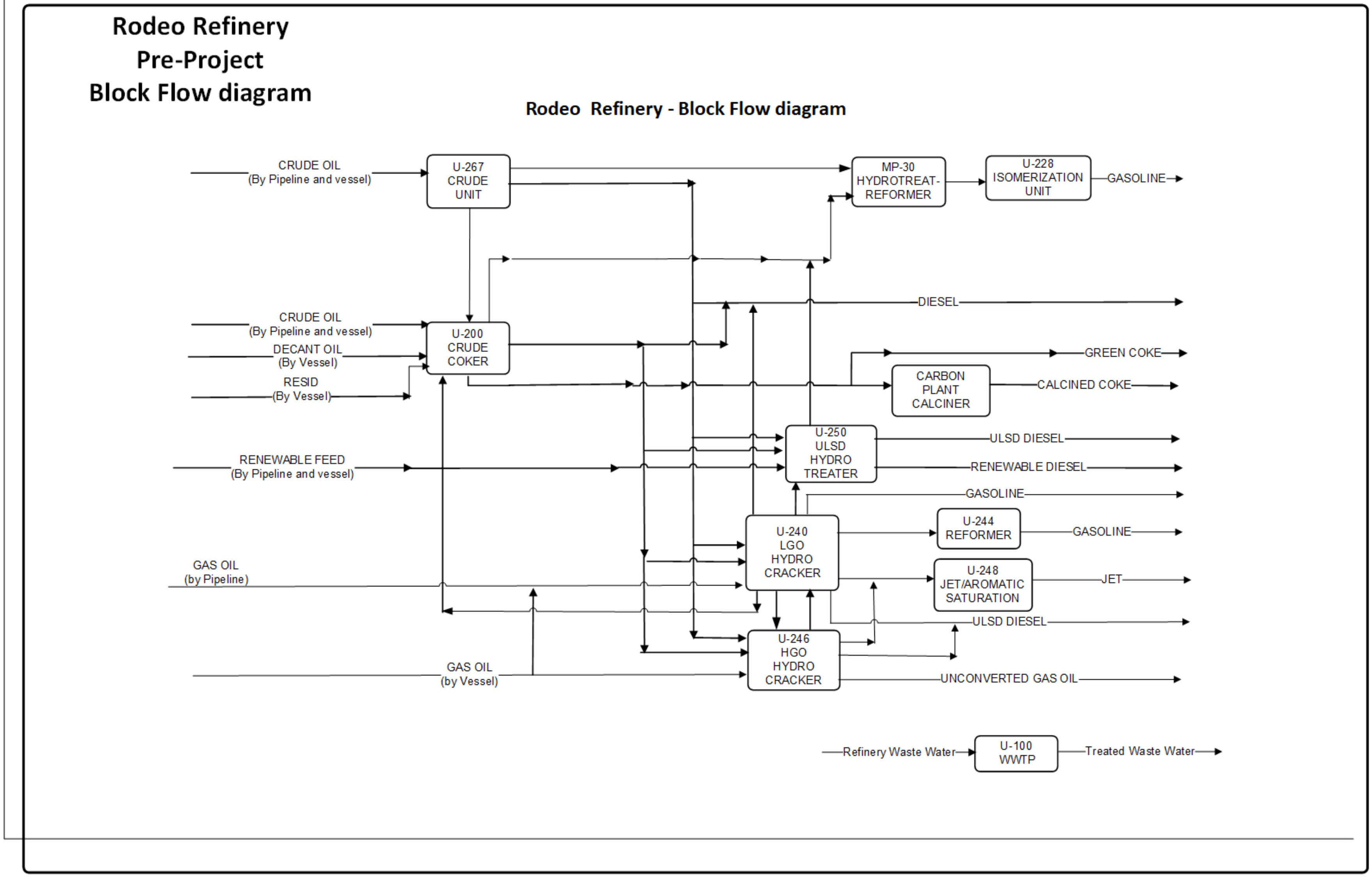
The process equipment at the Rodeo Site includes the following major units:

- Crude Distillation Unit (U267) and Delayed Coking Unit (U200): separate crude oil into petroleum coke (as a by-product) and a variety of gases, heavy residuals, and intermediate-weight feedstocks;
- Unicracker (U240/244/246/248): a complex of units that processes selected outputs of the Crude/Coker Unit into gasoline, diesel, and jet fuel distillate stocks as well as butane;
- Ultra-Low Sulfur Diesel (ULSD) Hydrotreating Unit (U250): produces renewable and conventional ultra-low sulfur diesel blending stock;
- Hydrotreating-Reformer (MP-30): a complex of process units that remove sulfur and nitrogen compounds from gasoline blend stocks;
- Isomerization Unit (U228): produces a key gasoline blending stock;
- Fractionation and Caustic Treatment (U215): produces butane and gasoline blending stock and removes sulfur compounds from fuel gas and butane;
- Product Blending facility (U40/76/80): mixes blending stocks and additives to produce consumer-ready gasoline and diesel and delivers the products to storage tanks for transportation;
- Sulfur Recovery/Amine Absorbers/Sour Water Strippers (U235/236/238): remove sulfur compounds and ammonia from refinery process streams;
- Main and MP-30 Flares: safely control excess gas; and
- Fuel Gas Center (U233): removes sulfur compounds from raw fuel gas.

The Rodeo Refinery also includes the Steam Power Plant containing gas turbines that generate steam and up to 50 megawatts of electricity for refinery use, a butane storage and railcar loading facility near the Marine Terminal, a wastewater treatment facility (U100), a vapor recovery system, a hydrogen generator, the Carbon Plant Site (approximately 1.5 miles south of the refinery in Franklin Canyon) that upgrades the petroleum coke by-product, and other support facilities.

The Refinery’s products are transported out of the refinery by vessel, pipeline, truck, and rail. Liquid products (principally, gasoline and diesel fuel) are loaded onto tanker or barge vessels at the Marine Terminal via pipeline from onshore storage tanks. Gasoline, jet fuel, and diesel fuel are shipped by pipeline to distribution points throughout California. Butane is loaded onto railcars for shipment to blending facilities and other customers.

Figure 2-2. Pre-Project Block Flow Diagram



2.2 Proposed Conditions and Facilities

To convert the Refinery into a facility that manufactures liquid transportation fuels from renewable feedstocks, the Project would repurpose existing refinery equipment to the extent possible. **Figure 2-3** shows the post-project flow diagram. Two existing hydrocrackers, Unit 240 (S307) and Unit 246 (S434), are the process units that will be utilized for producing renewable diesel, renewable naphtha, and renewable jet fuel.

There will be no physical change to any heaters at the Rodeo Facility. There is no proposed increase in the maximum heat input capacity or the potential to emit for any process heater. The heaters will be operated within permitted design parameters.

Existing equipment and infrastructure will be used for receiving, transferring, and storing future renewable feedstocks and renewable products. Minimal physical changes will be necessary to repurpose the existing Rail Butane Loading Rack (S70 - exempt source) for receiving renewable feedstocks.

Storage tank changes are detailed below in **Section 2.3**. Three tanks will undergo roof changes for feedstock storage. Tanks 100 and 153 will be converted from floating roofs to cone roofs and will be nitrogen blanketed. Vapors from Tank 100 will go to carbon adsorption. Tank 107 will have a geodesic dome installed. Tank 224 is a cone roof tank. For the project, Tank 224 will be connected to the Refinery's existing vapor recovery system. One gasoline blend stock tank (Tank 110) will not be physically modified but will be altered to increase the current throughput limit. Several tanks will have service changes to renewable feedstocks and renewable products, but no physical changes.

The renewable feedstocks may include, but are not limited to, soybean oil, tallow, used cooking oil, inedible corn oil, canola oil, FOG, and other vegetable-based oils. A new feedstock Pretreatment Unit (PTU) will be constructed for the Project to remove solids and other impurities that might harm the processing catalyst. Initially, the PTU will consist of two parallel processing trains that could process approximately 53,000 barrels per day (12-month rolling average) of renewable feedstock. A third processing train will be added to the PTU at a later date and result in total processing capacity of approximately 80,000 barrels per day (12-month rolling average) of renewable feedstock at the PTU.

Once the Project is in operation, no petroleum crude oil would be processed at the Rodeo Facility. Up to 80,000 barrels/day, on a 12-month rolling average, of renewable feedstocks could arrive at the Rodeo Facility and would be processed in the PTU. The majority of the time, the feedstocks treated by the PTU would be processed on-site to produce renewable fuels. In situations where there was excess treated feedstock produced by the PTU not processed on-site, this material could be exported from the refinery via the Marine Terminal.

Unlike fossil feed, renewable feedstock has a low sulfur content. A new Unit 237 Sulfur Treatment Unit (STU) will be installed with abatement devices that are equipped to treat low sulfur off-gas. Two of the three existing Sulfur Recovery Units (Units 236 and Unit 238) will be shutdown; Unit 235 will remain and be used primarily as a backup to the new STU.

The Project is expected to continue to use certain existing units, including storage tanks, interconnecting piping, wastewater treatment, the Steam Power Plant, some cooling towers, flares, loading and unloading facilities, blending and shipping facilities, and the Unit 233 Fuel Gas Center.

In addition to minor piping and other ancillary equipment changes, a summary of changes to the Rodeo Refinery as part of the Project are outlined below:

- U240 Unicracker: Replace two existing reactor vessels at end of life. Replace and modify existing heat exchangers. Add new process surge vessel, charge pump, minor chemical storage tanks and feed filters. Retray four existing distillation towers.
- U246 Hydrocracker: Replace and modify existing heat exchangers. Add new minor chemical storage tanks and feed filters. Retray two existing distillation towers
- New PTU: Install new equipment (3 parallel processing trains) to decontaminate and condition the renewable feedstocks prior to processing. The decontamination process removes metals and other solids that would harm the ability of the hydroprocessing units to produce renewable transportation fuel. The process includes a combination of vacuum drying, adsorption, filtration, centrifugal separation, and fats oils and grease (FOG) recovery. Some new silos and tanks will be installed within the unit.
- New STU: Install new unit with two trains. Each train will consist of a thermal oxidizer, waste heat boiler, caustic scrubber tower and fresh and spent caustic tanks to control ammonia and H_2S off-gases.
- Rail Butane Loading Rack: Repurpose existing butane rail loading stations for the unloading of renewable feeds. Install new steam piping connections to warm up and liquify renewable feed in rail cars prior to unloading.

As shown in **Table 2-1** below, once the Project is complete, several process units would not be operational.

Table 2-1. Process Equipment Changes for the Rodeo Renewed Project

Process Units	Existing Refinery	Rodeo Renewed Project[1]
Unit 267 - Crude	Operational	Not Operational / Relinquish Permit
Carbon Plant - Coke Calciner	Operational	Not Operational / Relinquish Permit
Units 236 - Sulfur Recovery Unit	Operational	Not Operational / Relinquish Permit
Unit 238 – Sulfur Recovery Unit	Operational	Not Operational / Relinquish Permit
Unit 200 - Delayed Coker	Operational	Not Operational / Maintain Permit
Unit 244 - Reformer	Operational	Not Operational / Maintain Permit
MP-30 - Naphtha HT/Reformer	Operational	Not Operational / Maintain Permit
Unit 228 - Isomerization	Operational	Not Operational / Maintain Permit

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[1] The permits for Unit 267, Carbon Plant and Units 236/238 will be relinquished upon startup of the Project. The permits for Unit 244, Unit 200, MP-30, and Unit 228 are being maintained as there is a remote possibility that, pending future economic and regulatory conditions, the units may be used. Although any such use is currently speculative, the potential use of these units has been included as a part of the environmental analysis and no reductions in emissions have been taken to account for the non-operational status of the units. Any future use of the units would be evaluated in accordance with CEQA and all applicable laws and regulations.

Table 2-1. Process Equipment Changes for the Rodeo Renewed Project

Process Units	**Existing Refinery**	**Rodeo Renewed Project**[1]
Unit 215 – Fractionation and Caustic Treatment	Operational	Not Operational / Maintain Permit
Unit 233 - Fuel Gas Center	Operational	Operational
Unit 250 - DHT/Renewable Diesel	Operational	Operational
Unit 240 - Light Hydrocracker	Operational	Operational
Unit 246 - Heavy Hydrocracker	Operational	Operational
Unit 248 - Jet/Aromatics Saturation	Operational	Operational
Unit 235 Sulfur Recovery	Operational	Operational
Unit 100 - Wastewater Treatment	Operational	Operational
Unit 110 - Hydrogen Plant	Operational	Operational
Unit 40/76/80 - Blending and Shipping	Operational	Operational
Marine Terminal	Operational	Operational
Rail Car Loading/Unloading	Operational	Operational
Steam Power Plant - Cogen	Operational	Operational
Main and MP-30 Flares	Operational	Operational
U237 Sulfur Treatment Unit	Not Present	New Construction
Feed Pretreatment Unit	Not Present	New Construction

Figure 2-3. Post-Project Block Flow Diagram

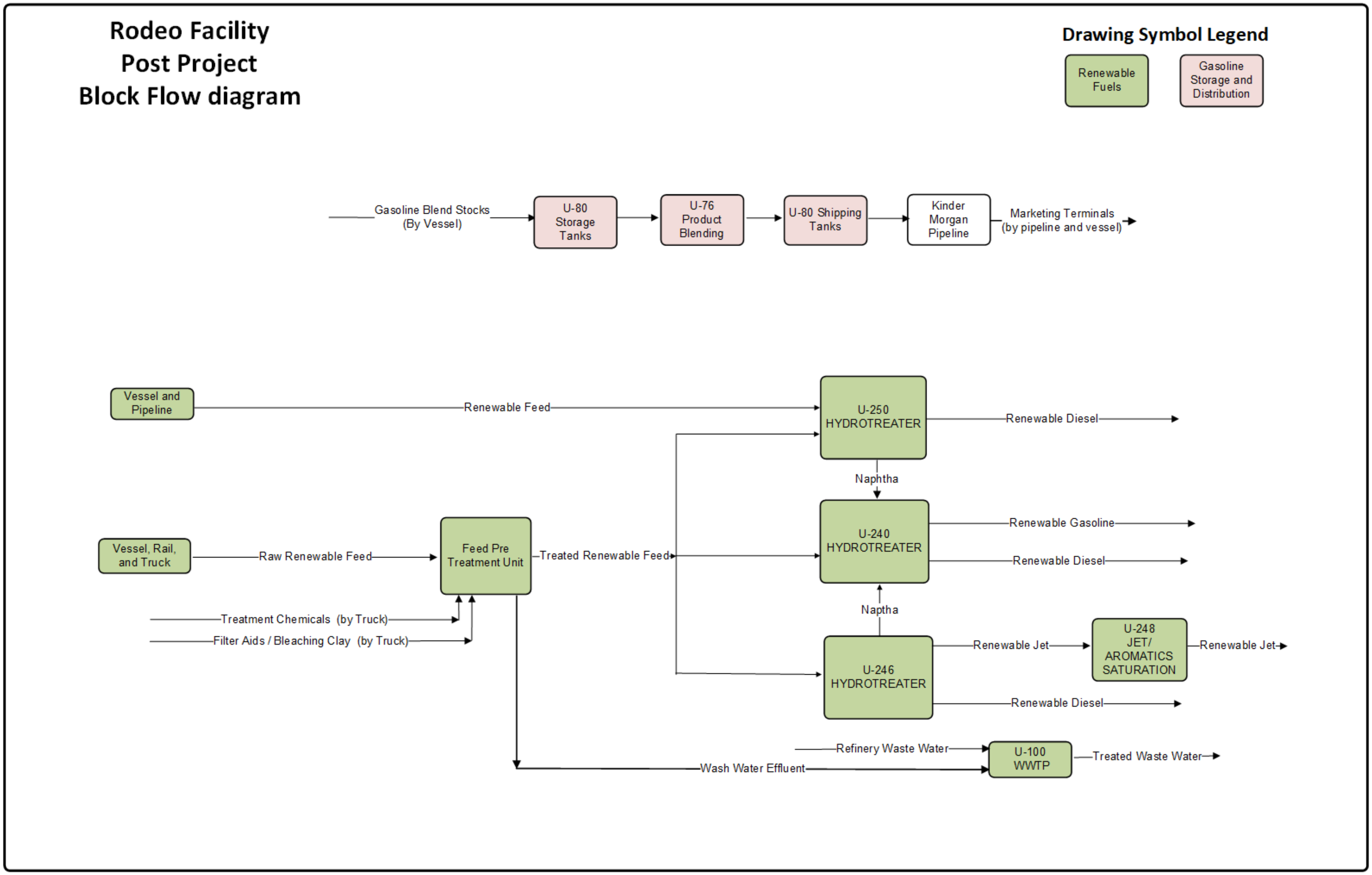
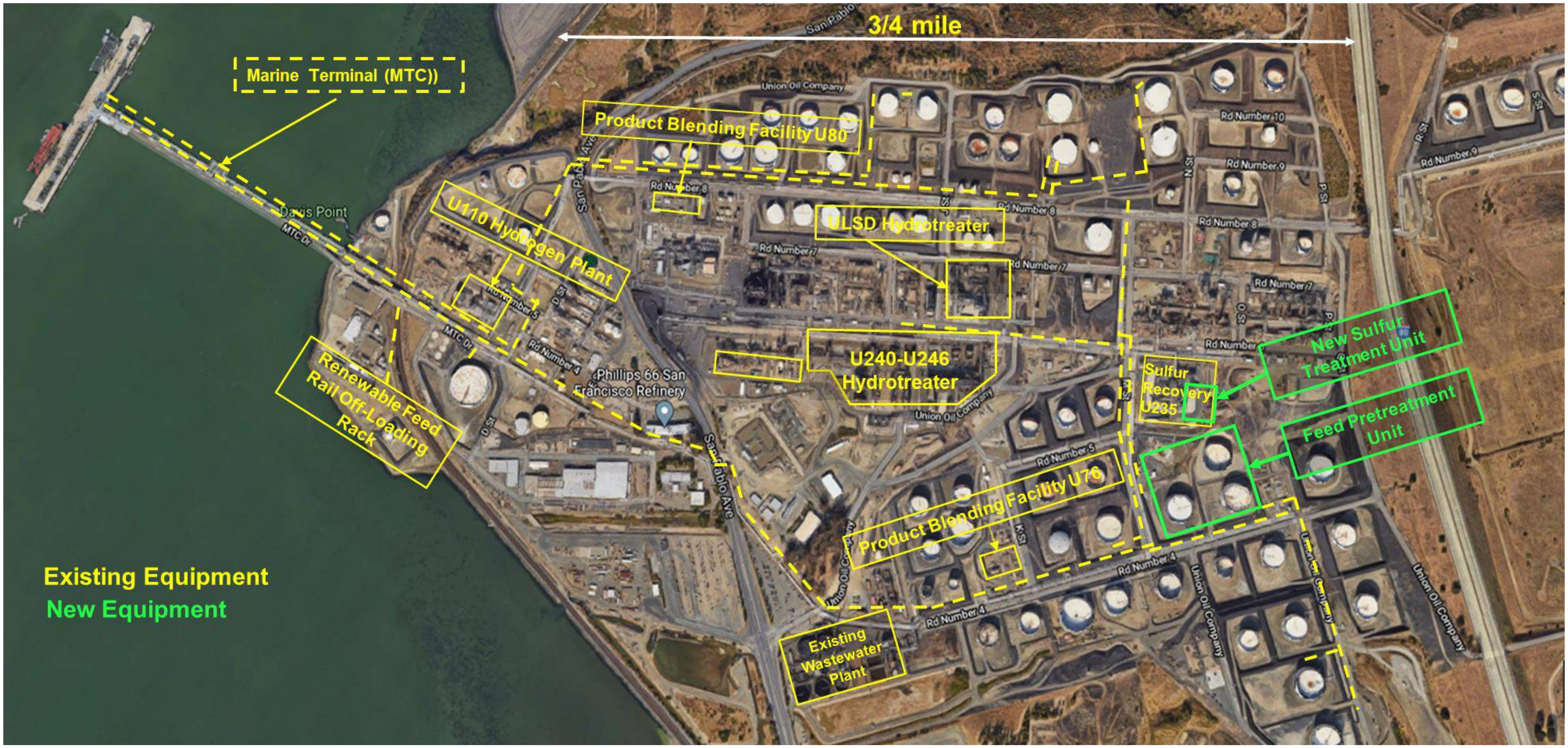


Figure 2-4. Map of Post-Project Facility



2.2.1 Unit 240 Unicracking Unit/Hydrotreater (S307)

The Project would adapt the Unicracking Unit 240 to make it capable of processing renewable feed to produce renewable diesel, renewable jet fuel, and renewable naphtha. As part of the Project, two existing reactor vessels that are at the end of their useful life would be replaced. The renewable feed is much lower in sulfur than petroleum feedstock feed. It is necessary to use a sulfiding agent on the catalyst and amine for stabilization. Two new chemical tanks and injection pumps would be installed. The existing heat exchangers would be replaced and/or adapted for new process conditions. A new process surge vessel and charge pump and feed filters would also be added. Four distillation towers would be retrayed. Unit 240 and Unit 246 will process renewable feedstocks at a rate that is less than or equal to the currently permitted capacity. Permit Condition 22965 limits the combined throughput of S307 and S434 to less than or equal to 69,000 barrels/day. No changes are proposed to Permit Condition 22965.

2.2.2 Unit 246 Hydrocracking Unit/Hydrotreater (S434)

After the Project the Unit 246 Hydrocracker would process renewable feed to produce renewable diesel, renewable jet fuel, and renewable naphtha. As part of the Project, existing heat exchangers would likely be replaced and minor chemical storage tanks, and feed filters would be added. Two distillation towers would be retrayed. The combined throughput limit in Permit Condition 22965 would apply to this source as well as S307. Permit Condition 22969 limits the throughput for S434 to 9,855,000 barrels over any rolling 12-month period. No change to this permit condition is requested. This source would not be altered or modified as part of the Project.

2.2.3 Feedstock Receiving and Product Loading

The Rodeo Facility will bring in renewable feedstock by marine, rail and truck. Renewable products will be shipped primarily by pipeline and using vessels at the Marine Terminal. Gasoline blend components will be received by vessel and finished gasoline will be shipped by pipeline. The Project will result in increased rail and marine traffic due to the renewable feeds and products. Truck traffic will decrease because coke product will no longer be trucked out and sulfur production will be significantly reduced. The Project includes the following changes to the Marine Terminal and the butane loading racks.

2.2.3.1 Marine Terminal Loading Berth M1 (S425) and Loading Berth M2 (S426)

No physical changes will be made to the Marine Terminal. The Marine Terminal will no longer receive crude oil; therefore, a change in Condition 4336 is requested.

2.2.3.2 Rail Butane Loading Racks (S-70 - Exempt)

Existing butane rail loading racks will be adapted for the unloading of renewable feeds into feed tanks. As part of the Project, new steam piping connections would be installed to warm up the renewable feed in the rail cars prior to unloading. This source is exempt from permitting and will continue to be exempt from permitting.

2.3 Storage Tanks

Four storage tanks that will store renewable feedstocks will have physical changes, but there is no proposed increase in their emissions or throughput limits. One gasoline blend stock storage tank will not have any physical changes but an increase in throughput above the current limit is requested. Several tanks will have service changes only.

- Tank 100 (S97) will be the primary storage for high pour point feedstock, such as tallow. Physical modification will include converting the tank from an external floating roof to a cone roof tank with vapor control. The vapor space of the tank will be blanketed with nitrogen. Any excess vapors generated during tank filling or due to tank breathing for instance, will be routed out of the tank and through carbon canisters prior to release to atmosphere. The tank will be insulated and the temperature of the material in the tank will be approximately 130 degrees F. On the suction draw of the tank, part of the material in Tank 100 will go directly to the PTU and part will go to a new heat exchanger. The heat exchanger will use steam to heat the feedstock. This flow of hot material from the exchanger will be recirculated back to the tank. A mixer will distribute the hot material throughout the tank to maintain the temperature in Tank 100. Steam coils will be added to the tank, but no steam or condensate lines will be installed. The steam coils will just be for emergency use, for example if the heat exchanger is down for a longer period and steam is necessary to warm up or melt the material in the tank if it starts to solidify. Current Permit Condition 25477 Part 1 limits the throughput of S97 to 15,571,000 barrels in any rolling continuous 12-month period. The condition also restricts the tank to storing only crude oil. No increase in the permit limit is requested, but the restriction on the product stored will need to be changed.
- Tank 107 (S334) will store renewable feedstocks. A geodesic dome will be installed over the external floating roof to provide an air gap insulation. There will be minor floor repairs and new coating of the floor and shell. NSR Permit Condition 22478, Parts 4 limits S334 to storing only crude oil or a petroleum liquid with a true vapor pressure less than or equal to 3.0 psia. Part 7 limits the throughput of S334 to 10,000,000 barrels in any consecutive 12-month period. No increase in the permit limit is requested, but the restriction on the product stored and the vapor pressure limit will need to be changed because the tank will be an internal floater capable of storing material up to < 11 psia per Regulation 8-5.
- Tank 110 (S440) is an external floating roof tank that will store gasoline blend stock. NSR Permit Condition 12125 Part 1 limits the throughput of S440 to 3,600,000 barrels in any rolling continuous 12-month period. No physical changes to this tank are required, but an increase to 6,000,000 barrels in any rolling continuous 12-month period is requested. This tank will only contain materials with a true vapor pressure less than 10.92 psia.
- Tank 153 (S108) will store renewable feedstocks. Physical modification will include converting the tank from a floating roof to a cone roof tank with a nitrogen blanket. The tank will be insulated. The material will run hot into the tank from the unit. The temperature of the tank will be approximately 130 degrees F. External steam coils will be added, but steam and condensate lines will not be installed. The steam coils will only be used in emergency if the tank loses heat and the material hardens. The tank is currently exempt from permitting in accordance with BAAQMD Rule 2-1-123.3.2. This exemption applies to the storage or loading of organic liquids where the initial boiling point (IBP) of the organics is greater than 302 degrees F and exceeds the actual storage temperature by at least 180 degrees F. Post-project, the tank will be exempt from permitting in accordance with BAAQMD Rule 2-1-123.3.6.

- Tank 224 (Tank 224) is an exempt cone roof tank that currently stores heavy gas oil. It will store renewable feedstocks in the future. The tank will be physically modified by connecting this tank to the existing Vapor Recovery System (A7). The tank is currently exempt from permitting in accordance with the high IBP exemption (BAAQMD Rule 2-1-123.3.2). Post-project, the tank will be exempt from permitting in accordance with BAAQMD Rule 2-1-123.3.6.

2.4 Feed Pretreatment Unit (PTU)

A new feed PTU will remove impurities from the renewable feedstocks before processing. Impurities may harm the reactor catalysts. The process includes a combination of vacuum drying, adsorption, filtration, centrifugal separation, and FOG recovery. Throughput of the unit will be 80,000 barrels per day.

The PTU will consist of three parallel processing trains to pretreat the raw feed. Two of the trains will have a polyethylene removal section. All three trains will have acid washing/special degumming section and an adsorption section. Supporting processes include closed loop systems, a Clean in Place (CIP) System, and a wastewater conditioning system. New equipment includes a Wet Surface Air Cooler (WSAC), tanks, bulk silos, a dissolved air flotation unit, filters mixers, heat exchangers and centrifuges. **Figure 2-4** shows the location of the Unit. **Figure 2-5** is a process flow diagram for the PTU.

2.4.1 PTU Vapor Recovery Systems

The PTU process utilizes reactors, vessels, tanks and other equipment for polyethylene removal, degumming, and adsorption processes. Some of this equipment operates under vacuum and others at atmospheric pressure. Each of the three PTU trains has a closed loop system to collect, control and discharge all vapors and gases from the process.

The PTU includes a FOG recovery process that consists of tanks, vessels, centrifuges, and evaporator units to remove organic material from process wastewater before treatment at the existing facility wastewater treatment plant. Removed organic matter is concentrated to remove excess moisture before being loaded onto trucks for shipment outside of the facility. All tanks, process vessels, and the dissolved air flotation unit (DAF) are connected to a Closed Loop Vapor Collection System, similarly to the PTU trains.

All collected vapors from the Closed Loop Vapor Collection Systems are sent to the Vapor Treatment System. Each Closed Loop Vapor Collection System/Treatment System will be a source of emissions. See the exempt source list in **Section 3.3**.

Collected vapors are treated for VOC removal using 2-stage treatment technology before being released to atmosphere. The proposed 1st stage treatment is biofilter and the 2nd stage unit is activated carbon adsorption.

2.4.1.1 Biofilter

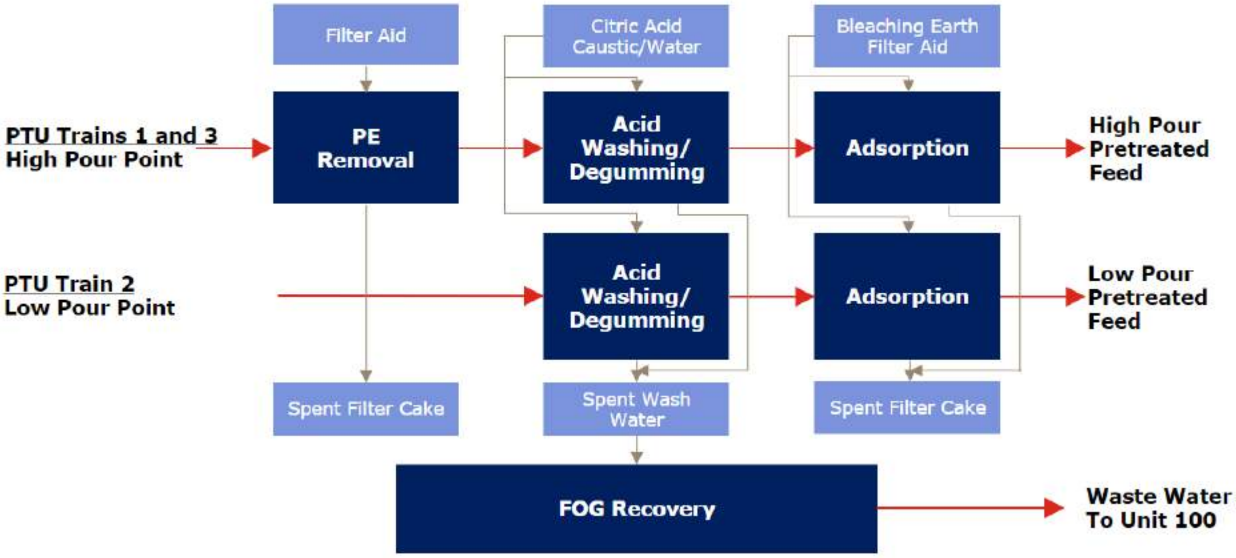
A biofilter uses microorganisms to degrade organic constituents in the vapor to carbon dioxide and water. The biofilter reactor consists of three major sections: the lower section, the middle section, and the upper section.

Vapors collected from the PTU enter the lower section of the biofilter. The lower section is an empty space allowing the collected vapor to flow upward and equally distribute through the media. The middle section is filled with media allowing microorganisms growth on it. The media can be compost peat, wood chips, tree bark, or proprietary materials supplied by the biofilter provider. The media provides a large surface area, nutrients, and moisture for microbial activities and adsorption of organic molecules. The treated vapor is discharged from a nozzle located at the upper section of the biofilter to the downstream activated carbon bed for polishing. The upper section is also an empty space allowing the spray water to equally distribute to the media to maintain bed moisture level under the suitable level for bacteria growth. The excess water sprayed from the upper section through the media will cascade down to the lower section, and then drain to the existing Unit 100 Wastewater Treatment Plant for treatment. A water seal design on the biofilter drain prevents the vapor from releasing the biofilter without being treated through the system. A bypass line bypasses the biofilter to the activated carbon bed. This allows operations to temporarily shut down the biofilter system during maintenance periods without shutting down the complete treatment system.

2.4.1.2 Activated Carbon Adsorption Unit

The activated carbon adsorption unit is a proven technology for removing volatile organic compounds from the inlet air stream. The activated carbon is replaced and disposed periodically when the bed reaches its breakthrough point. A two-canister system is implemented to ensure there is no breakthrough to atmosphere. A line bypassing the activated carbon beds will allow operations personnel to continue to use the biofilter during replacement of the spent activated carbon.

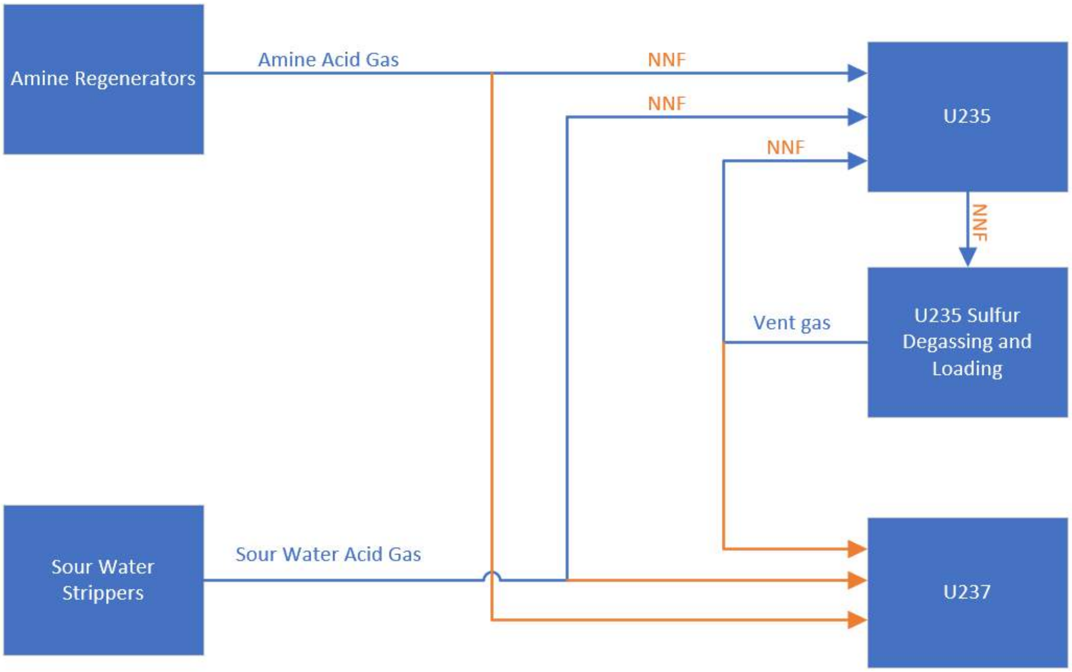
Figure 2-5. PTU Process Flow Diagram



2.5 Unit 237 Sulfur Treatment Unit (STU)

The Project will result in less amine acid gas and sour water acid gas to process. Two of the three existing Sulfur Recovery Units (Unit 236 and Unit 238) will be shutdown; Unit 235 will remain and be used primarily as a backup to the new Unit 237 STU. Unit 237 will include a new abatement package. The STU includes two trains. Each train will have a low-NO_x thermal oxidizer followed by caustic scrubbing of the SO_2. The oxidizer converts H_2S to SO_2 and converts the ammonia primarily to nitrogen, with some residual NO_x formation. The caustic scrubber removes the SO_2. The treated exhaust gas from the scrubber will be vented to atmosphere through a cold stack. The existing Unit 235 will be utilized if it is needed during unplanned outages of the thermal oxidizers and/or scrubbers. **Figure 2-6** is a process flow diagram for the STU.

Figure 2-6. STU Process Flow Diagram



2.5.1 Thermal Oxidation

Acid gas is combusted in the oxygen deficient reduction furnace to destroy virtually all NH_3 while minimizing NO_x. Reduction furnace temperature is designed to be operated at a minimum of 2000°F for stable combustion and near-complete NH_3 destruction. Because ammonia is being directly combusted, there is more nitrogen present than typical thermal oxidizer combustion where the only source of nitrogen is combustion air. Therefore, there is opportunity for NO_x formation. Combustion products are subsequently quenched with air for thermal oxidation of residual combustibles in the oxidation furnace.

2.5.2 SO_2 Scrubber

SO_2 will be quenched and scrubbed with a circulating caustic stream through a packed bed for SO_2 absorption. Caustic will be continuously made up to the scrubber to maintain a sufficient pH to prevent equipment corrosion and ensure high SO_2 absorption. The exhaust gas from the scrubber is vented to atmosphere via a new stack supported by the column.

3. AIR PERMIT APPLICABILITY

This section contains a discussion of four categories of emission sources: new, modified/altered, exempt, and shutdown. A description of sources in each category is included, along with the regulatory basis for the determination in each case. Other existing sources not discussed here will not be associated with the Project.

3.1 New Sources

Most of the sources associated with the Project will be existing equipment that have been re-purposed for use in generating renewable fuels. New permitted sources include the PTU with three parallel processing trains to pretreat the raw feed and a train to recover FOG. Additionally, a new STU will be installed to control ammonia and H_2S gases. Other sources within the PTU, including a Wet Surface Air Cooler (WSAC), four vapor recovery systems, a DAF, and 34 bulk silos are exempt from permitting and the appropriate exemptions are identified in **Section 3.3**. Therefore, there are two new sources to be permitted:

- PTU; and
- Unit 237 STU

Emissions from these sources are calculated in **Appendix B**, and a summary of emissions from these units is listed in **Table 1**.

3.2 Modified/Altered Sources

Under the definition found in BAAQMD Rule 2-1-234, a source has been “modified” if it undergoes a physical change or change in method of operation that results in one of the following types of emissions increases:

1. Any increase in daily or annual potential to emit (PTE), or
2. An increase in emissions that qualifies as a Federal Major Modification.

Based on the definition in BAAQMD Rule 2-1-233, a source is considered “altered” if it experiences a physical change, change in method of operation, or other similar change that may affect air pollutant emissions and that does not qualify as a modification.

For the first type of emissions increase, an increase in a source’s PTE would occur if there is a change that results in a need to increase a permitted emission limit. This would also occur if there is an increase in a permitted production rate or throughput that results in a higher calculated PTE. For grandfathered sources that do not have enforceable limits on emissions, throughput or production, the source’s PTE is determined based on the source’s actual physical ability to emit air pollution.

The second type of emissions increase is referred to as the “Federal Backstop” test by BAAQMD in its September 2016 “Complex Permitting Handbook for BAAQMD New Source Review Permitting.” This test to determine if the Project qualifies as a Federal Major Modification is included in **Section 8** of this application.

<u>Altered/Modified Source Evaluation</u>

The existing PTE for sources undergoing a physical change or change in the method of operation is listed in **Table 1**. The PTE values have been determined based either on permit limits on emissions or throughputs, as appropriate. The post-project PTE for evaluated sources is listed in **Table 1**.

The “Federal Backstop” test to determine if the Project qualifies as a Federal Major Modification is included in **Section 8** of this application. As discussed in this section, the Project will not result in a Federal Major Modification. It should be noted that the change in actual emissions is conservative because this analysis does not account for emissions the Rodeo Facility “could have accommodated” using Federal guidance. As a result, the emissions increase would be even smaller than what is shown in these calculations.

The following is a list of existing sources that will undergo a physical change or change in the method of operation as a result of the Project as described in **Section 2**, and that have been evaluated to determine if these should be considered either modified or altered sources. The results of the evaluation are shown in the last column of **Table 3-1**.

Table 3-1. Modified/Altered Sources

Source No.	Description	Proposed Change	Category
97	Tank #100	Physical change to tank to add insulation and convert roof to floating roof	Altered
307	U240 Hydrotreater	Physical change to unit to replace two existing end of life reactor vessels	Altered
334	Tank #107	Physical change to tank to add geodesic dome over existing floating roof	Altered
440	Tank #110	Increase in permitted limit to 6,000,000 bbl/yr with a TVP < 10.92 psia	Altered

In summary, the pre-project and post-project potential to emit from sources that are physically changed or will have a change in the method of operation were evaluated. The only source with an increase in throughput will be Tank 110 (S-440). However, the tank will only hold materials with a TVP <10.92 psia so there will not be an increase in PTE and, therefore, Tank 110 will be altered and not modified. A Federal Backstop test was also performed for new and modified/altered sources. Because the Project does not constitute a Federal Major Modification, there are no modified sources. Other sources in this analysis have not been modified and should therefore be considered altered sources.

Please note that the following are not considered as physical changes or changes in the method of operation requiring an evaluation of an emissions increase:

1. *Changes in tank contents* – There are some existing tanks associated with the Project that will be repurposed to store different materials. For many of these tanks, no physical change is required to accommodate this change. The change in tank contents could have been done under the existing air permit and is not considered a “physical change or change in the method of operation.” As a result, changes in tank contents have not been evaluated as potential alterations or modifications to existing tanks. For these changes, it was also confirmed that there would be no increase in permitted PTE for each tank because the combination of throughput and vapor pressure of new materials would not result in higher potential emissions. Also, no changes to allowable limits are required to accommodate the new materials for these tanks.

2. *Combustion units fired on Fuel Gas (FG) from renewable fuel production* – The production of renewable fuels will produce FG used as a fuel in combustion systems at the Rodeo Facility. The composition of renewable FG will be within the same ranges as FG currently used. No physical changes or changes in method of operation are required to continue to use FG as a fuel. There will also be no increase in permitted emissions or throughputs related to the FG.
3. *Unit 246 Hydrotreater* – After the Project, Unit 246 would process renewable feeds and produced renewable fuels. As described above, minor changes to equipment components will be made but these changes will not affect emissions. No changes to permit limits are required to accommodate the planned component changes.

3.3 Exempt Sources

Sources are exempt from the requirement to obtain an air permit if they qualify for one of the categorical exemptions listed in BAAQMD Rule 2-1. Sources may also be considered exempt if they have emissions below 10 pounds per day (lb/day) or 150 pounds per year (lb/year). To qualify for a permit exemption, sources must also demonstrate that they are not subject to any of the provisions of BAAQMD Rules 2-1-316 through 319.

The following is a list of equipment associated with the Project that qualify for a permit exemption, along with the regulatory citation for the applicable exemption:

Table 3-2. Exempt Sources

Source No.	Description	Basis for Permit Exemption
70	Current Butane Loading Rack Future Feedstock Off-loading Rack	Current: BAAQMD Rule 2-1-123.3.1 – Storage or loading of liquified gases Future: BAAQMD Rule 2-1-123.6 Storage or loading of liquid soaps, liquid detergents, tallow or vegetable oils, waxes or wax emulsions,
108	Tank No. 153	Current: BAAQMD Rule 2-1-123.3.2 Future: BAAQMD Rule 2-1-123.6
Tank 224	Tank No. 224	Current: BAAQMD Rule 2-1-123.3.2 Future: BAAQMD Rule 2-1-123.3.6
New/PTU	WSAC	BAAQMD Rule 2-1-128.4 – Water cooling towers not used for evaporative cooling of process water
New/PTU	DAF	BAAQMD Rule 2-1-103: Source not subject to any district rule[2]
New/PTU	Closed-Loop Vapor Recovery for PTU Train 1	BAAQMD Rule 2-1-103
New/PTU	Closed-Loop Vapor Recovery for PTU Train 2	BAAQMD Rule 2-1-103
New/PTU	Closed-Loop Vapor Recovery for PTU Train 3	BAAQMD Rule 2-1-103

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[2] The new DAF at the new PTU would be subject to BAAQMD Rule 8-8 as it is an air flotation unit. However, there are no requirements under 8-8-307 because the design rated capacity is smaller than 25.2 liters/second (400 gallons per minute). Any emissions from the DAF are reported under the closed-loop vapor recovery for PTUFOG recovery process.

Table 3-2. Exempt Sources		
Source No.	**Description**	**Basis for Permit Exemption**
New/PTU	Closed-Loop Vapor Recovery for PTU FOG Recovery	BAAQMD Rule 2-1-103
New/PTU	Bleaching Earth Storage Silo (F-400A)	BAAQMD Rule 2-1-115.1.4.4 – Storage Silos for Particulate Sources at Quarries, Mineral Processing and Biomass Facilities
New/PTU	Bleaching Earth Storage Silo (F-400B)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400C)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400D)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400E)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400F)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400G)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400H)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400I)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400J)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400K)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Bleaching Earth Storage Silo (F-400L)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401A)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401B)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401C)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401D)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401E)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401F)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401G)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401H)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Filter Aid Storage Silo (F-401I)	BAAQMD Rule 2-1-115.1.4.4
New/PTU	Poylethylene Removal Filter Aid Day Hopper (F-502A)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Poylethylene Removal Filter Aid Day Hopper(F-502B)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526A)	BAAQMD Rule 2-1-115.1.4.5

Table 3-2. Exempt Sources

Source No.	Description	Basis for Permit Exemption
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526B)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Filter Aid Adsorption Day Hopper (F-527)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626A)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626B)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Filter Aid Adsorption Day Hopper (F-627)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Poylethylene Removal Filter Aid Day Hopper (F-702A)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Poylethylene Removal Filter Aid Day Hopper (F-702B)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726A)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726B)	BAAQMD Rule 2-1-115.1.4.5
New/PTU	Filter Aid Adsorption Day Hopper (F-727)	BAAQMD Rule 2-1-115.1.4.5

The following is a demonstration that these potentially exempt sources do not trigger any of the additional provisions of BAAQMD Rules 2-1-316 through 319, and therefore qualify for an air permit exemption. A comparison of exempt source emissions to applicable thresholds listed below can be found in **Table 2**.

BAAQMD Rules <u>2-1-316 to 319 Analysis</u>

2-1-316.1: Sources that exceed Regulation 2, Rule 5 TAC trigger levels

> These units each do not have the potential to emit TACs in an amount that exceeds any of the trigger levels in Regulation 2, Rule 5.

2-1-316.2: Sources that emit at least 2.5 tons/year of any single hazardous air pollutant (HAP) or 6.25 tons/year of any combination of HAPs.

> These units each do not have the potential to emit HAPs in quantities that exceed the listed thresholds.

2-1-317: Public Nuisance Sources

> A source loses its permit exemption if it receives two or more public nuisance violations, under Regulation 1, Section 301 or Section 41700 of the California Health & Safety Code, within any consecutive 180-day period. The silos and most tanks are not odorous. Most process and storage tanks have vapor recovery and treatment to remove POCs. It is not anticipated that the Project will cause a public nuisance.

2-1-318: Hazardous Substances: PSD sources that emit greater than any of the following:

- 0.6 tpy of lead,

- 0.007 tpy of asbestos (except demolition, renovation, and waste disposal),
- 0.0004 tpy year of beryllium,
- 0.1 tpy of mercury,
- 1 tpy of vinyl chloride,
- 3 tpy of fluorides,
- 7 tpy of sulfuric acid mist, and
- 10 tpy of reduced sulfur compounds (including hydrogen sulfide).

Annual emissions from these exempt sources will not exceed any of the thresholds listed above.

2-1-319.1: Sources with emissions of any regulated air pollutant greater than 5 tons per year, after abatement (except greenhouse gases).

These units each do not emit any regulated pollutant (other than GHGs) in amounts greater than 5 tons/year.

3.4 Shutdown Sources

As mentioned in **Section 2,** a handful of sources would no longer be operational with the Project. **Table 3-3** presents a list of equipment that will be shutdown. Phillips will surrender the BAAQMD operating permits for these sources. Emission reductions from these sources are included in the emissions offset applicability discussion below. This table also includes three storage tanks (Tank 154, Tank 109, Tank 112) that will be out of service and the reduction in their emissions will be used as contemporaneous offsets.

Table 3-3. Shutdown Sources

BAAQMD Source Number	Unit	Description
29	200	Unit 200 B-5 Heater
30	200	Unit 200 B-101 Heater
36	200	Unit 200 B-1012 Heater
109	40	Tank #154
301	234	Molten Sulfur Pit 234
302	236	Molten Sulfur Pit 236
303	238	Molten Sulfur Pit 238
350	267	Unit 267 Crude Distillation Unit
351	267	Unit 267 B-601/602 Tower Preheaters
439	40	Tank #109
442	40	Tank #112
1002	236	Unit 236 Sulfur Plant
1003	238	Unit 238 Sulfur Plant
Plant ID 21360	--	Carbon Plant (all sources)

4. APPLICABLE BAAQMD REGULATIONS

The following is a discussion of BAAQMD air quality regulatory requirements for the Project.

4.1 Regulation 2 – Permit Rules

The applicability of relevant rules under Regulation 2 for new and modified sources are discussed in this section.

4.1.1 Regulation 2, Rule 1 – General Requirements

This rule includes the criteria for the issuance or denial of permits, a list of sources and activities that are exempt from permitting, and methods for appealing decisions on applications.

This regulation remains applicable to the Rodeo Facility. A discussion of air permit applicability for new, modified, altered, exempt and demolished sources associated with the Project is included in **Section 3**.

The Project is subject to review under CEQA. There are no schools within 1000 feet of the Rodeo Facility, and the Project does not constitute a new Major Source, a Major Modification, or a PSD project. Therefore, public notice of the proposed permit issuance is not required.

4.1.2 Regulation 2, Rule 2 – New Source Review

BAAQMD has adopted New Source Review (NSR) requirements for new and modified sources of air emissions in Regulation 2, Rule 2 (“Permits, New Source Review”). The primary requirements of this rule include a requirement to use Best Available Control Technology (BACT) and to purchase emissions offsets, for sources and pollutants that exceed applicable regulatory trigger levels.

4.1.2.1 BACT

New and modified sources with a potential to emit 10 lb/day or more of listed NSR pollutants that propose an emissions increase must employ BACT. The Rodeo Facility will trigger the BACT threshold of 10 lb/day for fugitive emissions from new equipment leaks at the PTU (flanges, valves, pumps, compressors) as shown in **Table 1**. There are no modified sources. A BACT analysis for PTU process component fugitive emissions is presented in **Section 6**.

The new STU (Unit 237) will employ an abatement system with secondary emissions of NO_x greater than 10 lb/day. These emissions qualify for the BACT exemption in BAAQMD Rule 2-2-102 and are therefore subject to the requirement to perform a Reasonably Available Control Technology (RACT) analysis. A discussion on RACT for the STU is presented in **Section 7.**

In accordance with BAAQMD Regulation 2-2-610, “cargo carriers” are not subject to BACT. This includes emissions from Ocean Going Vessels (OGVs) loading or unloading cargo and rail unloading cargo associated with a project.

4.1.2.2 Offsets

According to Regulation 2, Rule 2, emissions offsets are required at a 1:1 ratio for facilities with a potential to emit more than 100 tons/year of $PM_{2.5}$, PM_{10}, or sulfur dioxide (SO_2) that propose an increase in emissions. For emissions of NO_X or POC, offsets are required at a 1:1 ratio for facilities with a potential to emit more than 10 tons/year, and these offsets are available from the BAAQMD Small Facility Banking Account. Offsets are required at a 1.15:1

ratio for facilities with a potential to emit more than 35 tons/year of NO_X or POC, and such facilities must purchase their own offsets.

Consistent with BAAQMD Rule 2-2-610, emissions from "cargo carriers" must be included when evaluating the applicability of the offset requirement. This includes emissions from Ocean Going Vessels (OGVs) loading or unloading cargo and rail unloading cargo associated with a project. As part of this application, Phillips 66 is proposing to increase emissions associated with OGV and rail traffic. These emission increases have been included in determining whether offsets are required.

An offsets analysis is shown in **Table 3.** As shown in this table, there is an overall decrease in emissions with the Project and offsets will not be required.

4.1.2.3 PSD

BAAQMD Rule 2-2-224 defines a "PSD project" as a combination of new and modified sources that qualify as a new Major PSD Facility or that result in a "significant" emissions increase at an existing facility. This analysis is limited to Federal attainment pollutants. Since BAAQMD is a Federal nonattainment area for ozone and $PM_{2.5}$, direct emissions of $PM_{2.5}$ and emissions of POC are not included in this analysis.

As described above, there are no modified sources associated with the Project. Additionally, in accordance with BAAQMD Regulation 2-2-610, "cargo carriers" are not subject to PSD. This includes emissions from Ocean Going Vessels (OGVs) loading or unloading cargo and rail unloading cargo associated with a project. As a result, no modified sources or cargo carrier sources are required to be included in the PSD analysis.

For new sources, as per BAAQMD Rule 2-2-604.1, the PTE from each source should be used in evaluating PSD Project applicability. The new sources that emit PSD pollutants are shown in **Table 4**. As shown in this table, the total Project emissions for each pollutant are below the PSD significance threshold. As a result, the Project does not constitute a PSD Project. Requirements including the PSD BACT requirement and the requirement to perform a PSD Source Impact Analysis are not triggered for the Project.

4.1.2.4 Federal Major Modification Applicability Analysis

An analysis to determine if the Project qualifies as a Federal Major Modification is included in **Section 8** below. As seen in this section, the Project does not meet the criteria to be considered a Federal Major Modification.

4.1.2.5 CEQA

The Project is undergoing review and approval process under the California Environmental Quality Act (CEQA). Contra Costa County is acting as Lead Agency and developing an Environmental Impact Report (EIR). Evaluations of air quality, climate change and health risk impacts will be conducted in accordance with the current BAAQMD CEQA Guidelines.

4.1.3 Regulation 2, Rule 4 – Emissions Banking

This rule includes procedures for emissions banking and offsets. Phillips 66 will evaluate contemporaneous emission reductions in this application and may address future banking of excess reductions from shutdown sources in separate applications submitted under BAAQMD Regulation 2, Rule 4.

4.1.3.1 Regulation 2, Rule 5 – New Source Review of Toxic Air Contaminants

Under this rule, a Health Risk Assessment (HRA) is required for proposed increases in emissions of air toxics that exceed trigger thresholds listed in BAAQMD Table 2-5-1. This includes emissions increase from cargo carriers associated with the Project. A project is considered acceptable if the acute and chronic noncancer risk is below a calculated Health Index (HI) of 1.0, and annual emissions associated with the project would result in a lifetime incremental cancer risk equal to or less than 10.0 in a million. Sources with calculated cancer risk greater than 1.0 in a million or chronic HI greater than 0.20 must meet limits determined to represent Best Achievable Control Technology for Toxics (TBACT). Cargo carriers are exempt from the TBACT requirements according to 2-5-505.

This regulation will be applicable. As shown in **Table 5**, emissions for the Project exceed the trigger thresholds in BAAQMD Table 2-5-1 so an HRA is required for the Project. An HRA is being prepared and will be submitted separately.

4.1.3.2 Regulation 2, Rule 6 – Major Facility Review

This rule establishes procedures for large facilities to obtain Title V permits and includes standards, administrative requirements, and monitoring requirements.

As a result of the Project, Rodeo Facility emissions will decrease overall. However, the facility-wide PTE of one or more regulated pollutants will remain above 100 tpy threshold so the Facility will remain subject to this rule. The application forms requesting changes to the Facility's current Title V permit are included with this application.

4.2 Regulation 6 – Particulate Matter

This regulation includes several rules designed to reduce emissions of particulate matter.

4.2.1 Regulation 6, Rule 1 – General Requirements

This rule limits the quantity of particulate matter in the atmosphere by controlling emission rates, concentration, visible emissions, and opacity. This regulation would still generally apply to all sources at the Rodeo Facility.

4.2.2 Regulation 6, Rule 5 – Particulate Emissions from Refinery FCCUs

This rule limits the emissions of condensable particulate matter emissions from petroleum refinery fluidized catalytic cracking units (FCCUs) as well as emissions of precursors of secondary particulate matter. An FCCU is a processing unit that converts heavy petroleum fractions, typically from crude oil distillation units, into lighter fuel intermediates by using a fine, powdered catalyst to promote a chemical reaction in which the heavy petroleum molecules are broken into smaller molecules. The Rodeo Facility does not have and will not have an FCCU as defined by this rule, so this rule is not applicable to the Facility or the Project.

4.2.3 Regulation 6, Rule 6 – Prohibition of Trackout

This rule limits the emissions of particulate matter emissions due to trackout of solid materials onto paved public roads outside the boundaries of Large Bulk Material Sites, Large Construction Sites, and Large Disturbed Surface sites. For each type of area, this rule defines "large" sites as those sites where the total land area covered by construction activities, bulk material handling operations and disturbed surfaces is greater than 1 acre. For the Project, the combined area covered by construction activities, bulk material handling operations and disturbed surfaces will be smaller than 1 acre. Therefore, the provisions of this rule do not apply.

4.3 Regulation 7 – Odorous Substances

This regulation establishes general limitations on odorous substances and specific emission limitations on certain odorous compounds. This regulation would still apply to the Project.

4.4 Regulation 8 – Organic Compounds

This regulation includes rules to limit organic pollutant emissions from various sources.

4.4.1 Regulation 8, Rule 3 – Architectural Coatings

This rule limits the quantity of VOC in architectural coatings and will continue to apply when architectural coatings are used at the Rodeo Facility.

4.4.2 Regulation 8, Rule 5 – Storage of Organic Liquids

This rule limits emissions of organic compounds from storage tanks. New renewable feedstock storage tanks would be exempt per Rule 8-5-117, based on low vapor pressure. This rule would still apply for existing storage tanks.

4.4.3 Regulation 8, Rule 6 – Organic Liquid Bulk Terminals and Bulk Plants

This rule limits emissions of organic compounds from transfer operations at non-gasoline organic liquid bulk terminals and bulk plants. This rule does not currently apply to the facility. This rule contains the following definitions:

> ***8-6-201 Bulk Plant:*** *Until December 1, 1994, any storage and distribution facility that receives organic liquid by pipeline, railcar, and/or delivery vehicle; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles or transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of not more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure.*
>
> ***8-6-204 Bulk Terminal:*** *Until December 1, 1994, any storage and distribution facility that receives organic liquid; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles and transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure.*

The Facility will not meet either of these definitions after the Project is implemented because the Facility will not load non-gasoline organic liquids into delivery vehicles and/or transportable containers. Therefore, this rule will not apply after the Project is implemented.

4.4.4 Regulation 8, Rule 8 – Wastewater Collection and Separation Systems

This rule limits the emissions of organic compounds from wastewater collection and separation systems that handle liquid organic compounds from industrial processes. The existing WWTP has sources subject to this rule that would continue to be subject to this rule. The new DAF at the new PTU would be subject to this regulation as it is an air flotation unit, though there are no requirements because the design rated capacity is smaller than 25.2 liters/second (400 gallons per minute).

4.4.5 Regulation 8, Rule 18 – Equipment Leaks

This rule limits emissions of total organic compounds from equipment leaks at petroleum refineries, chemical plants, bulk plants, and bulk terminals. This rule contains the following definitions:

> ***8-18-203 Chemical Plant:*** *Any facility engaged in producing organic or inorganic chemicals and/or manufacturing products by chemical processes, including (1) any facility or operation that has 325 as the first three digits in the North American Industrial Classification Standard (NAICS) code, (2) any facility that manufactures industrial inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic and other manmade fibers; drugs; soap, detergents and cleaning preparations; perfumes, cosmetics, and other toilet preparations; paints, varnishes, lacquers, enamels, and allied products; agricultural chemicals; safflower and sunflower oil extracts; and (3) any facility engaged in re-refining.*
>
> ***8-18-213 Petroleum Refinery:*** *Any facility that processes petroleum products as defined in North American Industrial Classification Standard Number 32411, Petroleum Refining.*

After the Project is implemented, the Facility will be classified under NAICS code category 325 (“Chemical Manufacturing”). Therefore, the Facility will meet the definition of a chemical plant under this rule and will not be classified as a petroleum refinery for purposes of this rule. This regulation would still apply to the Facility, though the VOC content of process streams would be reduced compared to current operations.

4.4.6 Regulation 8, Rule 22 – Valves and Flanges at Chemical Plants

This rule limits emissions of precursor organic compounds from valves and flanges at chemical plants. The Rodeo Facility would be exempt from this rule due to compliance with Regulation 8, Rule 18.

4.4.7 Regulation 8, Rule 28 – Episodic Releases from Pressure Relief Devices as Petroleum Refineries and Chemical Plants

This rule prevents episodic emissions of organic compounds from pressure relief devices on equipment handling gaseous organic compounds at petroleum refineries and collects information on episodic organic and inorganic compound emissions from pressure relief devices at petroleum refineries and chemical plants. This rule contains the following definitions:

> ***8-28-201 Chemical Plant:*** *Any facility engaged in producing organic or inorganic chemicals and/or manufacturing products by chemical processes. Any facility or operation that has 325 as the first three digits in the North American Industrial Classification Standard (NAICS) Code. Chemical plants may include, but are not limited to the manufacture of: industrial inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic and other man-made fibers; drugs; soap, detergents and cleaning preparations, perfumes, cosmetics and other toilet preparations; paints, varnishes, lacquers, enamels and allied products; agricultural chemicals; safflower and sunflower oil extracts; and re-refining, not including petroleum refineries.*
>
> ***8-28-209 Petroleum Refinery:*** *Any facility that processes petroleum as defined in the North American Industrial Classification Standard No. 32411 (1997).*

After the Project is implemented, the Facility will be classified under NAICS code category 325 ("Chemical Manufacturing"). Therefore, the Facility will meet the definition of a chemical plant under this rule and will not be classified as a petroleum refinery for purposes of this rule.

Recordkeeping and reporting requirements for chemical plants would apply once the Project is implemented.

4.4.8 Regulation 8, Rule 33 – Gasoline Bulk Terminals and Gasoline Delivery Vehicles

This rule limits the emissions of organic compounds associated with gasoline transfer operations at gasoline bulk terminals and organic compounds from gasoline cargo tanks. This rule has the following definitions:

> ***8-33-203 Gasoline Bulk Terminal:*** *A gasoline storage and distribution facility that receives gasoline by marine tanker, barge, pipeline, or rail car, and loads it into gasoline cargo tanks for delivery to gasoline bulk plants, service stations, and other distribution points.*
>
> ***8-33-204 Gasoline Cargo Tank:*** *Any container, including its associated pipes and fittings, that is attached to a vehicle used to transport gasoline and is required to be certified in accordance with Section 41962 of the California Health and Safety Code.*

The Facility does not currently load gasoline into gasoline cargo tanks and will not load gasoline into gasoline cargo tanks after the Project. Therefore, this rule would not apply.

4.4.9 Regulation 8, Rule 39 – Gasoline Bulk Plant and Gasoline Cargo Tanks

This rule limits the emissions of organic compounds associated with gasoline transfer operations at gasoline bulk plants and organic compounds from gasoline cargo tanks. This rule has the following definitions:

> ***8-39-203 Gasoline Bulk Plant:*** *A storage and distribution facility that receives gasoline by gasoline cargo tanks and loads it into gasoline cargo tanks for delivery to service stations and other distribution points.*
>
> ***8-39-204 Gasoline Cargo Tank:*** *Any container, including its associated pipes and fittings, that is attached to a vehicle used to transport gasoline and is required to be certified in accordance with Section 41962 of the California Health and Safety Code.*

The Facility does not currently load gasoline into gasoline cargo tanks and will not load gasoline into gasoline cargo tanks after the Project. Therefore, this rule would not apply.

4.4.10 Regulation 8, Rule 44 – Marine Tank Vessel Operations

This rule limits emissions of organic compounds into the atmosphere from marine tank vessel operations. This rule would remain applicable to marine tank vessel operations at the Rodeo Facility.

4.4.11 Regulation 8, Rule 53 – Vacuum Truck Operations

This rule limits the emissions of organic compounds from the use of vacuum trucks at petroleum refineries, bulk plants, bulk terminals, marine terminals, and organic pipeline facilities. The following is an evaluation of whether each of these categories would apply:

Table 4-1. BAAQMD Rule 8-53 Definitions	
Definition	**Applicability**
Petroleum Refinery: Any facility that processes petroleum products as defined in North American Industry Classification System code number 32411, Petroleum Refineries.	The Facility will not be classified under NAICS code 32411 after the Project is implemented.
Bulk Plant: A distribution facility that is subject to Regulation 8, Rule 39 or to Section 302 of Regulation 8, Rule 6.	The Facility will not be subject to either of these rules, as discussed in this section.
Bulk Terminal: A distribution facility that is subject to Regulation 8, Rule 33 or to Section 301 of Regulation 8, Rule 6.	The Facility will not be subject to either of these rules, as discussed in this section.
Marine Terminal: Any facility or structure constructed to load or unload organic liquid bulk cargo into or off of marine tank vessels	This Facility is currently (and will continue to be) subject to the rule requirements for marine terminals.
Organic Liquid Pipeline Facility: Any pipeline used to transport petroleum, petroleum products, or petroleum product blending stock, along with any associated breakout stations	The Facility will not use vacuum trucks to load material into or out of a pipeline.

After the Project is implemented, the Facility will still operate a marine terminal. Therefore, this rule would still apply after the Project.

4.5 Regulation 9 – Inorganic Gaseous Pollutants

This regulation includes rules to limit inorganic gaseous pollutant emissions from various sources.

4.5.1 Regulation 9, Rule 1 – SO_2

This rule establishes emission limits for sulfur dioxide (SO_2) from all sources including ships and limits ground level concentrations of SO_2. This regulation would still apply after implementation of the Project, though SO_2 emissions would decrease due to renewable feedstocks.

4.5.2 Regulation 9, Rule 2 – H_2S

This rule limits ground level concentrations of hydrogen sulfide (H_2S). This regulation would still apply after implementation of the Project, though H_2S emissions would decrease due to renewable feedstocks.

4.5.3 Regulation 9, Rule 7 – NO_x and CO from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

This rule limits the emissions of nitrogen oxides (NO_x) and carbon monoxide (CO) from industrial, institutional, and commercial boilers, steam generators, and process heaters. Section 9-7-110.3 contains a general rule exemption for "(b)oilers, steam generators and process heaters that are used in petroleum refineries." These units are instead subject to the NO_x and CO limits in BAAQMD Rule 9-10. Because the Facility will continue to meet the definition of a "petroleum refinery" in BAAQMD Rule 9-10, as discussed below, the requirements of BAAQMD Rule 9-7 will not apply.

4.5.4 Regulation 9, Rule 10 – NO_x and CO from Boilers, Steam Generators, and Process Heaters in Petroleum Refineries

This rule limits the emissions of NO_x and CO from boilers, steam generators, and process heaters, including CO boilers, located at petroleum refineries. A petroleum refinery is defined in BAAQMD Rule 9-10-213 as "any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives." The Rodeo Facility will continue to meet the definition of a petroleum refinery for purposes of this rule as a result of the Project, so this rule will remain applicable.

4.6 Regulation 10 – Standards for New Stationary Sources

This regulation establishes emission and performance standards for new plants and other sources. The rules are incorporated by reference to the provisions of Part 60, Chapter 1, Title 40 of the Code of Federal Regulations. The applicability of these standards is discussed in **Section 5.1**.

4.7 Regulation 11 – Hazardous Pollutants

This regulation sets emission and performance standards for hazardous pollutants from various sources. The rules are incorporated by reference to the provisions of Part 63, Chapter 1, Title 40 of the Code of Federal Regulations. The applicability of these standards is discussed in **Section 5.2**.

4.7.1 Regulation 11, Rule 7 – Benzene

This rule limits the emissions of benzene from the following sources intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges or other product accumulator vessels, and control devices or systems required by this rule. This rule would not be applicable because the Rodeo Facility did not and will not operate equipment "in benzene service", which is defined as "any equipment, which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight".

4.8 Regulation 12 – Miscellaneous Standards of Performance

This regulation establishes emission and performance standards for plants and operations that are not otherwise included in BAAQMD regulations.

4.8.1 Regulation 12, Rule 11 – Flare Monitoring at Petroleum Refineries

This rule requires monitoring and recording of emission data for flares at petroleum refineries. BAAQMD Rule 12-11-205 defines a petroleum refinery as "(a) facility that processes petroleum, as defined in the North American Industrial Classification Standard (NAICS) No. 32411, and including any associated sulfur recovery plant." The NAICS definition for this category is as follows: "This industry comprises establishments primarily engaged in refining crude petroleum into refined petroleum. Petroleum refining involves one or more of the following activities: (1) fractionation; (2) straight distillation of crude oil; and (3) cracking." The Rodeo Facility will no longer meet the definition of a petroleum refinery because it will not be engaged in refining crude and this rule will no longer be applicable. There will also be no new flares or modifications to existing flares at the Rodeo Facility as part of this Project.

4.8.2 Regulation 12, Rule 12 – Flares at Petroleum Refineries

The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. BAAQMD Rule 12-12-206 defines a petroleum refinery as "(a) facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant." The NAICS definition for this category is as follows: "This industry comprises establishments primarily engaged in refining crude petroleum into refined petroleum. Petroleum refining involves one or more of the following activities: (1) fractionation; (2) straight distillation of crude oil; and (3) cracking." The Rodeo Facility will no longer meet the definition of a petroleum refinery because it will not be engaged in refining crude and this rule will no longer be applicable. There will also be no new flares or modifications to existing flares at the Rodeo Facility as part of this Project.

4.8.3 Regulation 12, Rule 15 – Petroleum Refining Emissions Tracking

This rule tracks air emissions and crude oil composition characteristics from Petroleum Refineries and Support Facilities over time and establishes air monitoring systems to provide air quality data along refinery boundaries. BAAQMD Rule 12-15-210 of this rule defines a petroleum refinery as:

> ***Petroleum Refinery:*** *An establishment that is located on one or more contiguous or adjacent properties that processes crude oil to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks. Petroleum Refinery processes include separation processes (e.g., atmospheric or vacuum distillation, and light ends recovery), petroleum conversion processes (e.g., cracking, reforming, alkylation, polymerization, isomerization, coking, and visbreaking), petroleum treating processes (e.g., hydrodesulfurization, hydrotreating, chemical sweetening, acid gas removal, and deasphalting), feedstock and product handling (e.g., storage, crude oil blending, non-crude oil feedstock blending, product blending, loading, and unloading), and auxiliary facilities (e.g., boilers, waste water treatment, hydrogen production, sulfur recovery plant, cooling towers, blowdown systems, compressor engines, and power plants).*

The Rodeo Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project because the Facility will no longer process crude oil. As a result, this rule will no longer be applicable.

5. APPLICABILITY OF FEDERAL REGULATIONS

The following is a discussion of air quality regulatory requirements for the Project.

5.1 New Source Performance Standard (NSPS) Applicability

5.1.1 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db)

This NSPS applies to any steam generating unit that commenced construction, modification, or reconstruction after June 19, 1983 and has a heat input capacity from fuels combusted in the steam generating unit of more than 29 megawatts (MW). There will be no new combustion sources at the Rodeo Facility. In addition, under NSPS, existing sources are only considered to have been modified if they have an increase in hourly PTE, which will not occur as a result of the Project for any steam generating unit.

NSPS Subpart Db currently applies to the heat recovery steam generator burners (S355-S357). These sources will continue to be subject to the standard.

5.1.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc)

This NSPS applies to any steam generating unit that commenced construction, modification, or reconstruction after June 9, 1989 and has a heat input capacity from fuels combusted in the steam generating unit of less than 29 MW, but greater than 2.9 MW. This regulation was not previously applicable and will not be applicable as a result of the Project since there will be no new combustion sources at the Rodeo Facility.

5.1.3 Standards of Performance for Petroleum Refineries (40 CFR 60, Subpart J)

This NSPS applies to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day or less. The term petroleum refinery is defined in 40 CFR 60.101(a) as "any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives." The term "petroleum" is defined in 40 CFR 60.101(b) as "the crude oil removed from the earth and the oils derived from tar sands, shale, and coal."

The Rodeo Facility will no longer process crude oil so the Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project so this NSPS will not be applicable.

5.1.4 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR 60, Subpart Ja)

This NSPS applies to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares, and sulfur recovery plants. Except for flares and delayed coking units, the NSPS only applies to affected facilities that commenced construction, modification, or reconstruction after March 14, 2007. Flare and delayed coking units have different applicability dates. The definitions of the terms "petroleum refinery" and "petroleum" are nearly identical to the definitions of these terms listed above in 40 CFR 60, Subpart J. The Rodeo Facility will no longer process crude oil so the Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project so this NSPS will not be applicable.

5.1.5 Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 (40 CFR 60, Subpart K)

This NSPS applies to each storage vessel with a storage capacity greater than 40,000 gallons that is used to store petroleum liquids for which construction was commenced after May 18, 1978. Petroleum liquid storage vessels with a capacity less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer is exempt from this NSPS. This regulation would not be applicable to any new sources or the existing Tank 107 after the Project as this storage vessel will no longer store petroleum liquids as defined in 40 CFR 60 Subpart K.

5.1.6 Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 (40 CFR 60, Subpart Ka)

This NSPS applies to each storage vessel with a storage capacity greater than 40,000 gallons that is used to store petroleum liquids for which construction was commenced after May 18, 1978 and prior to July 23, 1984. Petroleum liquid storage vessels with a capacity less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer are exempt from this NSPS. This regulation would not be applicable to any new storage vessels at the Rodeo Facility and does not currently apply to any existing sources that will be modified as part of the Project.

5.1.7 Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (40 CFR 60, Subpart Kb)

This NSPS applies to each storage vessel with a storage capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids for which construction, reconstruction, or modification was commenced after July 23, 1984. Storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kilopascals are exempt from this NSPS.

This regulation was previously applicable to Tank 110 and would still be applicable after the Project as the tank will contain gasoline blend stock. All new storage vessels constructed as part of the Project would be exempt for a low vapor pressure based on 40 CFR 60.110b(b), which says "This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa."

5.1.8 Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) for Which

Construction, Reconstruction, or Modification Commenced After January 5, 1981, and On or Before November 7, 2006 (40 CFR 60, Subpart VV)

This NSPS applies to affected facilities in the synthetic organic chemicals manufacturing industry (SOCMI) that commenced construction, reconstruction, or modification after January 5, 1981 and on or before November 7, 2006. The regulation is currently applicable to sources at the Rodeo Facility including the flares, crude unit, isomerization, and the hydrogen plant. After the Project, this subpart may be applicable as the Rodeo Facility may still produce SOCMI chemicals listed in 40 CFR §60.489. However, as discussed below, the Facility will be subject to 40 CFR 63, Subpart FFFF and compliance with that subpart satisfies the requirements of 40 CFR 60, Subpart VV.

5.1.9 Standards of Performance for Equipment Leaks of VOC in the SOCMI for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (40 CFR 60, Subpart VVa)

This NSPS applies to affected facilities in the SOCMI that commenced construction, reconstruction, or modification after November 7, 2006. The regulation is currently applicable to sources at the Rodeo Facility including the flares and the cracking unit. After the Project, this subpart may be applicable as the Rodeo Facility may still produce SOCMI chemicals listed in 40 CFR §60.489. However, as discussed below, the Facility will be subject to 40 CFR 63, Subpart FFFF and compliance with that subpart satisfies the requirements of 40 CFR 60, Subpart VVa.

5.1.10 Standards of Performance for Bulk Gasoline Terminals (40 CFR 60, Subpart XX)

This NSPS applies to the total of all loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks and commenced construction or modification after December 17, 1980. A "loading rack" is defined in 40 CFR 60.501 as "the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tank trucks." The Facility will continue to handle gasoline after this Project. However, this rule will not be applicable since the Facility will not load gasoline to fill delivery tank trucks.

5.1.11 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006 (40 CFR 60, Subpart GGG)

This NSPS applies to compressors in petroleum refineries that commenced construction, reconstruction, or modification after January 4, 1983 and on or before November 7, 2006. The definitions of the terms "petroleum refinery" and "petroleum" are nearly identical to the definitions of these terms listed above in 40 CFR 60, Subpart J. The Rodeo Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project so this NSPS will not be applicable.

5.1.12 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (40 CFR 60, Subpart GGGa)

This NSPS applies to compressors in petroleum refineries that commenced construction, reconstruction, or modification after November 7, 2006. The definitions of the terms "petroleum refinery" and "petroleum" are nearly identical to the definitions of these terms listed above in 40 CFR 60, Subpart J. The Rodeo Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project so this NSPS will not be applicable.

5.1.13 Standards of Performance for VOC Emissions from the SOCMI Air Oxidation Unit Processes (40 CFR 60, Subpart III)

This NSPS applies to the following affected facilities for which construction, modification, or reconstruction commenced after October 21, 1983 that produce any of the chemicals listed in 40 CFR 60.617: air oxidation reactor not discharging its vent stream into a recovery system, air oxidation reactor and recovery system into which its vent stream is discharged, and combination of two or more air oxidation reactors and a common recovery system into which their vent streams are discharged. This regulation did not previously apply to the Rodeo Facility and will not be applicable after the Project either as the Rodeo Facility will not install any new air oxidation units.

5.1.14 Standards of Performance for VOC Emissions from SOCMI Distillation Operations (40 CFR 60, Subpart NNN)

This NSPS applies to the following affected facilities for which construction, modification, or reconstruction commenced after December 30, 1983 that produce any of the chemicals listed in 40 CFR 60.667 as a product, co-product, by-product, or intermediate: distillation unit not discharging its vent stream into a recovery stream, combination of distillation unit and the recovery system into which its vent stream is discharged, and each combination of two or more distillation units and the common recovery system into which their vent streams are discharged. This regulation did not previously apply to the Rodeo Facility and will not be applicable after the Project either as the Rodeo Facility will not install any new distillation units.

5.1.15 Standards of Performance for VOC Emissions from the Petroleum Refinery Wastewater Systems (40 CFR 60, Subpart QQQ)

This NSPS applies to individual drain systems, oil-water separators, and aggregated facilities located in petroleum refineries for which construction, modification, or reconstruction commenced after May 4, 1987. The definitions of the terms "petroleum refinery" and "petroleum" are nearly identical to the definitions of these terms listed above in 40 CFR 60, Subpart J. The Rodeo Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project so this NSPS will not be applicable.

5.1.16 Standards of Performance for VOC Emissions from the SOCMI Reactor Processes (40 CFR 60, Subpart RRR)

This NSPS applies to the following affected facilities for which construction, modification, or reconstruction commenced after June 29, 1990 that produce any of the chemicals listed in 40 CFR 60.667 as a product, co-product, by-product, or intermediate: reactor not discharging its vent stream into a recovery system, combination of a reactor process and the recovery system into which its vent stream is discharged, and each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged. This regulation did not previously apply to the Rodeo Facility and will not be applicable after the Project either as the Rodeo Facility will not install any new reactor processes.

5.2 National Emissions Standards for Hazardous Air Pollutants (NESHAP) Applicability

5.2.1 National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene (40 CFR 61, Subpart J)

This NESHAP applies to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by the NESHAP that are intended to operate in benzene service but does not apply to sources located in coke by-product plants. This NESHAP would not be applicable because the Rodeo Facility did not and will not operate equipment "in benzene service", which is defined as "a piece of equipment [which] either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight as determined according to the provisions of §61.245(d)."

5.2.2 National Emission Standard for Equipment Leaks (40 CFR 61, Subpart V)

This NESHAP applies to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by the NESHAP that are intended to operate in volatile hazardous air pollutant service. This regulation would not be applicable because the Rodeo Facility did not and will not operate equipment "in VHAP service", which is defined as "a piece of equipment [which] either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of 40 CFR §61.245(d)".

5.2.3 National Emission Standard for Benzene Waste Operations (40 CFR 61, Subpart FF)

This NESHAP applies to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries. This regulation currently applies to the Rodeo Facility on the basis of it being a petroleum refinery and will remain applicable after the Project on the basis of the Rodeo Facility being a chemical manufacturing plant as defined in 40 CFR §61.341.

5.2.4 National Emission Standard for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR 63, Subpart R)

This NESHAP applies to bulk gasoline terminals and pipeline breakout stations except for those that meet exemption requirements based on emission screening factors. The term "Bulk Gasoline Terminal" is defined in 40 CFR 63.421 as "any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day." This rule would become applicable as the Rodeo Facility will receive gasoline in quantities greater than 75,700 liters per day (and therefore will qualify as a Bulk Gasoline Terminal in this rule) after the Project.

5.2.5 National Emission Standard for Marine Tank Vessel Loading Operations (40 CFR 63, Subpart Y)

This NESHAP applies to new and existing operations where a commodity is bulk loaded onto a marine tank vessel from a terminal, which may include the loading of multiple marine tank vessels during one loading operation but does not include refueling of a marine tank vessel. The definition of "commodity" in this rule is not limited to petroleum products and includes materials with Total Vapor Pressure greater than or equal to 1.5 psia, per 40 CFR

63.560(d)(1), and HAP concentration greater than 0.5 weight percent, per 40 CFR 63.560(d)(5). This regulation currently applies to the marine loading berths and will continue to apply after the Project since materials that satisfy these parameters will continue to be loaded.

5.2.6 National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries (40 CFR 63, Subpart CC)

This NESHAP applies to petroleum refining process units and to the following related emission points when located at a plant site that is a major source and emit or have equipment containing or contacting one or more HAPs in Table 1 of the NESHAP: miscellaneous process vents from petroleum refining process units, storage vessels associated with petroleum refining process units, wastewater streams and treatment operations associated with petroleum refining process units, equipment leaks from petroleum refining process units, gasoline loading racks classified under Standard Industrial Classification (SIC) code 2911, marine vessel loading operations at a petroleum refinery, storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under SIC code 2911 located within a contiguous area and under common control with a refinery, heat exchange systems, and releases associated with the decoking operations of a delayed coking unit. The term "petroleum refining process unit" is defined in 40 CFR 63.641 as "a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911)…" and used primarily for listed activities, such as producing or separating fuels or related petroleum streams.

The Rodeo Facility equipment will no longer meet the definition of petroleum refining process units as a result of the Project, since the Facility will no longer belong to SIC code 2911, so this NESHAP will not be applicable.

5.2.7 National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR 63, Subpart UUU)

This NESHAP applies to petroleum refineries located at a major source of HAP emissions. The NESHAP establishes national emission standards for HAPs emitted from petroleum refineries and also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards. The term "petroleum refinery" is defined in 40 CFR 63.1561 as "an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411…" and used primarily for listed activities, such as producing or separating fuels or related petroleum streams.

The Rodeo Facility will no longer meet the definition of a petroleum refinery in this rule as a result of the Project, since the Facility will not belong to SIC code 2911 or NAIC code 32411, and this rule will no longer be applicable.

5.2.8 National Emission Standard for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) (40 CFR 63, Subpart EEEE)

This NESHAP applies to organic liquids distribution (OLD) operations that are located at, or are part of, a major source of HAP emissions. OLD operation means the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity performed. Activities include, but are not limited to, storage, transfer, blending, compounding, and packaging. The NESHAP establishes national emission limitations, operating limits, and work practice standards for organic HAPs from these operations.

Two existing tanks (Tank 21 and Fire Training Fluid Tank) are subject to this rule but are exempt based on size and will be unaffected by the Project. All modified and new tanks would be exempt from this rule based on the definition of organic liquids.

5.2.9 National Emission Standard for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing (40 CFR 63, Subpart FFFF)

This NESHAP applies to miscellaneous organic chemical manufacturing process units that are located at, or are part of, a major source of HAP emissions. The NESHAP establishes national emission limitations for HAPs for miscellaneous organic chemical manufacturing and also establishes requirements to demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards.

This regulation did not previously apply to the Rodeo Facility but will become applicable after the Project once the Rodeo Facility is no longer classified as a petroleum refinery. The Rodeo Facility will instead be classified under SIC code 2869 (Industrial Organic Chemicals, Not Elsewhere Classified) which is subject to the requirements of 40 CFR 63 Subpart FFFF.

5.2.10 National Emission Standard for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD)

This NESHAP applies to industrial, commercial, and institutional boilers and process heaters that are located at, or are part of, a major source of HAP with some exceptions as specified in 40 CFR 63.7491. The NESHAP establishes national emission limitations for HAPs emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAPs and also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards. This regulation will remain applicable to existing sources. There will be no new boiler or process heaters as a result of the Project.

5.2.11 National Emission Standard for Hazardous Air Pollutants: Site Remediation (40 CFR 63, Subpart GGGGG)

This NESHAP applies to site remediation activities that clean up a remediation material, are co-located at a facility with one or more other stationary sources that emit HAP and meet an affected source definition specified for a source category that is regulated by another subpart under 40 CFR 63, and are located at a facility that is a major source of HAP. Site remediation is defined as activities or processes used to remove, destroy, degrade, transform, immobilize, or otherwise manage remediation material. The NESHAP establishes national emission limitations and work practices for HAPs emitted from site remediation activities and also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards. This regulation was not previously applicable and will not be applicable after the Project.

6. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

6.1 BACT Selection Methodology

This section presents a BACT analysis for precursor organic compounds (POC) emissions from process component equipment leaks (flanges, valves, pumps, compressors) from the PTU at the Rodeo Facility, the only source determined to trigger BACT in the applicability evaluation discussed in **Section 4.1.2.1**.

According to BAAQMD Rule 2-2-202, BACT is defined as:

> *"Best Available Control Technology: An emission limitation, control device, or control technique applied at a source that is the most stringent of:*
>
> 1. *The most effective emission control device or technique that has been successfully utilized for the type of equipment comprising such a source; or*
>
> 2. *The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a sources; or*
>
> 3. *The most effective control device or technique or most stringent emission limitation that the APCO has determined to be technologically feasible for a source, taking into consideration cost-effectiveness, any ancillary health and environmental impacts, and energy requirements; or*
>
> 4. *The most effective emission control limitation for the type of equipment comprising such a source that is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitation is not achievable.*
>
> *Under no circumstances shall BACT be less stringent than any emission control required by any applicable provision of federal, state, or District laws or regulations."*

The following is an analysis of emission limits and control techniques that have been considered as BACT for equipment leaks (flanges, valves, pumps, compressors).

6.2 Listing of Potential Control Options

The BAAQMD's BACT/TBACT Workbook[3] includes BACT guidelines for fugitive emissions, including flanges, emergency pressure relief valves, process valves, pumps, and compressors. **Table 6-1** outlines the BAAQMD achieved-in-practice control options (BACT-2) and technologically feasible/cost effective control options (BACT-1) for POC.

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[3] BAAQMD. 2015. BACT/TBACT Workbook. Available on at: https://www.baaqmd.gov/permits/permitting-manuals/bact-tbact-workbook. Accessed: March 10, 2021.

Table 6-1. Potential Control Options

Equipment Type	BACT-1 (Technologically Feasible/ Cost Effective)	BACT-2 (Achieved in Practice)
Flanges	No determination	100 ppm, expressed as methane measured using EPA Reference Method 21
Emergency Pressure Relief Valves	Rupture disk w/ vent to fuel gas recovery system, furnace, or flare with a recovery/ destruction efficiency >98%	Vent to fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency ≥98% and BAAQMD approved design and operation
Process Valves	No determination	100 ppm, expressed as methane measured using EPA Reference Method 21
Pumps	100 ppm, expressed as methane measured using EPA Reference Method 21	500 ppm, expressed as methane measured using EPA Reference Method 21
Compressors	100 ppm, expressed as methane measured using EPA Reference Method 21	500 ppm, expressed as methane measured using EPA Reference Method 21

6.3 Achieved in Practice Control Options (BACT-2)

BAAQMD Regulation 8, Rule 18 requires implementation of a Leak Detection and Repair (LDAR) program. Under this program, leaks must be repaired within 7 days if the measured concentration of total organic compounds exceeds 100 ppm (as methane) with the exception of pumps, compressors, and pressure relief devices which must be repaired if they leak total organic compounds in excess of 500 ppm (as methane). Regulation 8, Rule 18 applies to petroleum refineries, chemical plants, bulk plants, and bulk terminals as discussed in **Section 4.4.5**. The Project will be subject to this rule as a “chemical plant.” These limits in Regulation 8, Rule 18 are consistent with a BACT-2 level of control, listed above, representing limits that have been achieved in practice.

In addition, BAAQMD BACT Guidelines contain a requirement for emergency relief pressure valves to be vented to a fuel gas recovery system, furnace, or flare with a recovery/ destruction efficiency greater than 98%.

These limits represent a minimum level of control that must be achieved as BACT, regardless of cost or other factors.

6.4 Technologically Feasible/Cost-Effective Control Options (BACT-1)

For pumps and compressors, BAAQMD BACT Guidelines contain a BACT-1 LDAR leak detection threshold of 100 ppm, the lower threshold also required for detecting leaks from valves and flanges. For emergency relief pressure valves, the BACT-1 requirement involves the use of a rupture disk, in addition to having emissions routed to a fuel gas recovery system that achieves a recovery efficiency of greater than 98%. These options are each considered feasible and will be selected as BACT, so no further analysis of cost effectiveness or technological feasibility is required.

6.5 Selection of BACT

The following control options are proposed as BACT for fugitive emissions from components added as part of this Project:

- **Flanges, process valves, pumps and compressors**: Implementation of an LDAR program consistent with the methodology and monitoring frequency of Regulation 8, Rule 18, where leaks must be repaired within 7 days if the measured concentration of total organic compounds exceeds 100 ppm (as methane); and
- **Emergency Pressure Relief Valves:** Use of a rupture disk, along with venting emissions to a fuel gas recovery system, furnace, or flare with a recovery/ destruction efficiency >98%.

7. REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)

BAAQMD Rule 2-2-102 contains a BACT exemption for "emissions of secondary pollutants that are the direct result of the use of an abatement device or emission reduction technique implemented to comply with the BACT or Best Available Retrofit Control Technology (BARCT) requirements for control of another pollutant." For these emissions, a RACT level of control is required.

The new STU, with thermal oxidizers and caustic scrubbers, is proposed to control NH_3 and H_2S emissions. This unit is subject to several BAAQMD regulations, including H_2S limits in Regulation 9, Rule 2 and Regulation 2, Rule 5. Since the STU is required to achieve compliance with BAAQMD regulations, the secondary emissions from the unit's abatement systems are exempt from BACT but must apply RACT. The NO_x emissions from the thermal oxidizers are secondary emissions with the potential to exceed the BACT threshold of 10 lb/day. These emissions qualify for the BACT exemption of BAAQMD Rule 2-2-102, and a RACT analysis has been performed. This section contains the methodology and results of this RACT analysis.

7.1 RACT Selection Methodology

This section presents a RACT analysis for NO_x emissions from the thermal oxidizers proposed as abatement systems for the STU. According to BAAQMD Rule 2-2-225, RACT is defined as:

> ***2-2-225 Reasonably Available Control Technology (RACT):*** *For sources that are to continue operating, RACT is the lowest emission limit that can be achieved by the specific source by the application of control technology taking into account technological feasibility and cost-effectiveness, and the specific design features or extent of necessary modifications to the source. For sources which are or will be shutdown, RACT is the lowest emission limit that can be achieved by the application of control technology to similar, but not necessarily identical categories of sources, taking into account technological feasibility and cost-effectiveness of the application of the control technology to the category of sources only and not to the shut-down source.*

The following is an analysis of control options that have been considered as RACT, consistent with this definition.

7.2 Listing of Potential Control Options

There are four possible control options that have been identified as possible RACT options for NO_x emissions from the thermal oxidizers:

1. Low-NO_x Combustion
2. Non-Selective Catalytic Reduction (NSCR)
3. Selective Non-Catalytic Reduction (SNCR)
4. Selective Catalytic Reduction (SCR)

Each of these measures is discussed below in terms of technological feasibility and cost effectiveness, as appropriate.

7.3 Evaluation of Control Options

The following is an evaluation of the control options evaluated as possible RACT options for NO_x emissions from the thermal oxidizers.

Low-NO_x Combustion

BAAQMD has adopted a policy entitled "NO_x and CO RACT Levels for Thermal Oxidizers" listing its current RACT requirements for thermal oxidizers used for compliance purposes.[4] The NO_x RACT emission listed in this policy is an exhaust concentration of 50 ppmv @15% oxygen, equivalent to an emission rate of 0.20 lb/MMBtu. The background for this limit listed in the BAAQMD guidance states that this NO_x limit was determined based on 17 of the District's source tests on thermal oxidizers conducted by the District's Source Test Section between 10/31/1997 and 7/08/1998.

Thermal oxidizers are most commonly natural gas-fired systems used to control VOC emissions. The NO_x emissions generated by these systems are the result of prompt NO_x formed by the oxidization of atmospheric nitrogen present in the combustion air at high temperatures. Therefore, the BAAQMD RACT limit would have included combustion-related emissions only. The thermal oxidizers are abatement devices used to control both ammonia and hydrogen sulfide generated by renewable fuels production. The ammonia sent to the thermal oxidizers is destroyed at combustion temperatures, producing a combination of nitrogen gas and additional process-related fuel NO_x emissions. As a result, a RACT limit for the thermal oxidizers must be developed that accounts for both combustion and process fuel NO_x emissions.

Based on the estimated conversion rate of ammonia to NO_x, the achievable RACT limit for the thermal oxidizers is estimated to be:

Table 7-1. RACT Limit

Component	**NO_x (lb/MMBtu)**
Combustion NO_x (BAAQMD RACT)	0.20
Process Fuel NO_x (Ammonia conversion)	0.20
Total NO_x	**0.40**

Non-Selective Catalytic Reduction (NSCR)

NSCR is an emission control technology that utilizes a catalyst to reduce NO_x emissions under fuel-rich conditions. The technology has been utilized to control emissions from automobile engines and from stationary source reciprocating engines. Use of NSCR to control emissions from combustion systems other than engines is rare. NSCR technology requires a

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[4] Policy found online at: https://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/bart_ract/noxandcoractforthermaloxidizers.pdf

fuel-rich environment for NO_x reduction, with exhaust content <1% oxygen, which will not be achievable by the thermal oxidizer exhaust. Therefore, NSCR is not a technically feasible control option for this case.

<u>Selective Non-Catalytic Reduction (SNCR)</u>

The use of SNCR involves the injection of ammonia or urea into an exhaust stream. The ammonia acts as a reducing agent in the exhaust, reducing NO_x to nitrogen gas (N_2) and water without the use of a catalyst. Use of this technology requires uniform mixing of the reagent and exhaust gas within a narrow temperature range (typically between 1600°F to 2100°F). Operations outside of this temperature range will significantly reduce removal efficiencies and may result in elevated ammonia emissions or increased NO_x emissions.

The use of SNCR would not be feasible since the exhaust from the thermal oxidizers would be below the required temperature range. A secondary issue is that SNCR is most effective for exhaust streams with high NO_x concentrations (typically 200-400 ppm). Concentrations of NO_x in the thermal oxidizer outlet are estimated to be well below this range. As a result, SNCR has been determined to be technologically infeasible for this application.

<u>Selective Catalytic Reduction (SCR)</u>

The use of SCR involves injection of ammonia or urea into an exhaust stream in the presence of a catalyst, typically made of a precious metal. This catalyst allows the NO_x reduction reaction to occur at temperatures lower than those required for SNCR. The ideal temperature range for base-metal SCR catalysts is between 600°F and 750°F, with zeolite catalysts capable of performing at temperatures between 600°F and 1100°F. The use of SCR would be technologically feasible for the Project, since the temperature downstream of the thermal oxidizer exhaust would be within the appropriate range for use of SCR. Therefore, a cost effectiveness calculation has been prepared using the methodology outlined in USEPA's Air Pollution Control Cost Manual and in BAAQMD BACT Guidelines.

The results of the cost effectiveness calculation are presented in **Tables 6 and 7**. As seen in these tables, the cost-per-ton of NO_x removed exceeds the BAAQMD NO_x BACT cost effectiveness threshold. For a RACT determination, use of an even lower cost threshold would be appropriate. Since SCR would not be considered cost effective as a BACT option for this source, it would also not be considered to be cost effective as a RACT option. As a result, the use of SCR has been eliminated as a RACT option for NO_x emissions from the thermal oxidizers, based on cost.

7.4 Selection of RACT

Because the add-on control options discussed above were determined to be either technologically infeasible or not cost-effective, the remaining option selected as RACT was the use of low-NO_x combustion. The NO_x emission limit proposed as RACT is 0.40 lb/MMBtu. This limit was determined considering both combustion and process-related fuel NO_x emissions from the thermal oxidizers used to abate ammonia and H_2S.

8. FEDERAL MAJOR MODIFICATION APPLICABILITY

8.1 New and Modified Sources

Under BAAQMD Rule 2-2-234 (definition of "modify"), projects must be evaluated to determine if they qualify as a Federal Major Modification. This analysis is referred to as the "Federal Backstop" test by BAAQMD in its September 2016 *Complex Permitting Handbook.*[5] For this test, BAAQMD Rule 2-2-224 references the Federal definitions of the term "major modification" found in 40 C.F.R. 51.165(a)(1)(v) for Federal nonattainment pollutants and in 40 CFR 52.21(b)(2)(i) for Federal attainment pollutants. To evaluate whether the Project is a "major modification" under these Federal rules, a calculation of the "emissions increase" has been performed consistent with Federal New Source Review (Federal NSR) requirements.

For projects involving both new and modified sources, a "hybrid" emissions increase test is required. Under this approach, the emissions increase from new sources is determined as the difference between the "baseline actual emissions" and the "proposed potential to emit." For modified sources, the emissions increase is calculated as the difference between "baseline actual emissions" and "projected actual emissions." The methodology used to determine these is described in the following sections.

A project may also be considered a Federal Major Modification if it results in a "net emissions increase." This is often referred to as a "netting" analysis. When performing this analysis, the sum of all creditable increases and decreases from the five years prior to a project is totaled for comparison with Federal NSR thresholds. This analysis is required under two scenarios. First, if a project results in an emissions increase (i.e., the increase in emissions from new and modified sources associated with the proposed project) that is significant, then a netting analysis may be used to demonstrate that a project is not a Federal Major Modification. Under United States Environmental Protection Agency (USEPA) regulations, a project triggers Federal NSR if it results in both an emissions increase and a net emissions increase. Secondly, a netting analysis may be required if a project relies on any emissions decreases to "net out" of an emissions increase.

8.2 New Sources - Potential Emissions

For new sources, an emissions increase is determined as the difference between the baseline actual emissions and the proposed potential to emit. Because the baseline actual emissions from a new source are zero, the emissions increase is equal to the new source's PTE. The PTE from new sources associated with the Project is summarized in **Table 1**. Supporting calculations are shown **Appendix B**.

8.3 Existing Sources - Projected Actual Emissions

For existing sources, "projected actual emissions" are defined in 40 CFR 52.21 as:

> *"… the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in*

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[5] BAAQMD. 2016. Complex Permitting Handbook for BAAQMD New Source Review Permitting. Available online at: https://www.baaqmd.gov/~/media/files/permits/permitting-manuals/nsr-guidance/complex-nsr-permitting-handbook_sept-2016-pdf.pdf?la=en. Accessed: March 10, 2021.

> *any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source."*

The projected actual throughput for existing equipment is based on business projections and the anticipated level of future operation for production of renewable fuels. Projected emissions are calculated based on the maximum predicted annual throughput in the 5 years following startup of the Project and emission factors representative of planned operation.

When calculating projected actual emissions, Federal NSR regulations also allow a source to exclude from the emissions increase calculation those emissions that could have previously been accommodated during the baseline period. The USEPA has indicated that emissions that could have been accommodated may be calculated based on the highest monthly operating level during the baseline period. These monthly emissions are then annualized (multiplied by 12) to determine an annual emission rate. This approach is outlined by USEPA in guidance for determining emissions a facility could have been accommodated prior to a project.[6] The difference between the baseline actual emissions and the annualized emissions a facility could previously have accommodated may be excluded from the Federal NSR applicability calculation.

8.4 Baseline Actual Emissions

Baseline actual emissions are the representative emissions based on any consecutive 24-month period in the ten years prior to the proposed modification. The baseline actual emissions for sources included in this analysis are listed in **Appendix B** and summarized in **Table 8**. The baseline selected for the Project was the 24-month period of operation from 2018 to 2019.

8.5 Emissions Increase

The attached **Table 8** lists the emissions increase from new and modified sources associated with the Project. As seen in this table, the Project will not result in a Federal Major Modification. It should be noted that the change in actual emissions is conservative since this analysis does not account for emissions the Rodeo Facility "could have accommodated" using Federal guidance. As a result, the emissions increase would be even smaller than what is shown in these calculations.

For these calculations, a netting analysis was not required, since the Project did not result in a significant emissions increase and since the Project did not rely on emissions decreases from any shutdown equipment to keep emissions under the significance threshold.

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[6] USEPA letter to Georgia-Pacific Wood Products, LLC dated March 18, 2010. Available online at: https://www.epa.gov/sites/production/files/2015-07/documents/demandgrowth.pdf. Accessed: March 10, 2021.

SUMMARY TABLES

Table 1
Summary of Baseline and Post-Project Potential to Emit
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Permitted Sources

Source Number	Description[1,2,3]	Project Status	Baseline Potential to Emit							Post-Project Potential to Emit							Change in Potential to Emit						
			CAPs						GHGs[4]	CAPs						GHGs	CAPs						GHGs
			NO_X	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	CO2e	NO_X	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	CO2e	NO_X	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	CO2e
			ton/yr						MT/yr	ton/yr						MT/yr	ton/yr						MT/yr
97	Tank 100	Altered	--	--	--	2.4	--	--	39	--	--	--	--	--	--	--	--	--	--	-2.4	--	--	-39
307	U240 Unicracking Unit	Altered	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.61	--	--	--
334	Tank 107	Altered	--	--	--	1.9	--	--	25	--	--	--	1.7	--	--	--	--	--	--	-0.28	--	--	-25
440	Tank 110	Altered	--	--	--	5.3	--	--	--	--	--	--	5.3	--	--	--	--	--	--	--	--	--	--
New/STU	U237 Sulfur Treatment Unit	New	--	--	--	--	--	--	--	25	8.8	5.2	0.34	6.4	6.4	27,184	25	8.8	5.2	0.34	6.40	6.40	27,184
New/PTU	Pretreatment Unit	New	--	--	--	--	--	--	--	--	--	--	3.3	--	--	--	--	--	--	3.3	--	--	--
		Total:	--	--	--	10	--	--	64	25	8.8	5.2	11	6.4	6.4	27,184	25	8.8	5.2	1.6	6.40	6.40	27,120

Notes:

[1] Baseline and Post-Project Potential to Emit calculations for tanks are presented in Stationary Source Table 9, with additional supporting information provided in Stationary Source Tables 10 - 15.

[2] Baseline and Post-Project Potential to Emit for U240 accounts for process component equipment leaks. For U240, the change in potential to emit was directly calculated in Stationary Source Table 7 using the net change in component count and default CAPCOA emission factors with historical leak rate data from facility's 2019 R12-15 inventory calculations. This emissions increase is reflective of an actual increase in component count, but the potential to emit is expected to be equivalent between the baseline and post-project scenarios, thus the source is altered and not modified.

[3] Post-Project Potential to Emit for all new sources assumed to be equivalent to Post-Project Actual emission rates. Emissions calculations are presented in Stationary Source Tables 1 - 5.

[4] Baseline CO_2e Potential to Emit for Tanks 100 and 107 calculated by multiplying the annual crude oil throughput by 0.1 MT of CH_4 (methane) per million barrels and then weighting by the global warming potential of methane (25). The annual crude oil throughput for baseline potential to emit conditions is shown in Stationary Source Table 14, the methane emission factor is consistent with ARB guidance, and the global warming potential is consistent with IPCC AR4.

Abbreviations:

CAPs - Criteria Air Pollutant
CO - carbon monoxide
CO_2e - carbon dioxide equivalents
GHGs - Greenhouse Gases
MT - metric ton
NOx - nitrogen oxides
PM_{10} - particulate matter less than 10 microns in diameter
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter
POC - precursor organic compounds
SO_2 - sulfur dioxide
yr - year

Table 2
Determination of Source Exemption Status
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Comparison of CAP Emissions to Requirements of 2-1-319.1

Source Number	Description	Project Status	Post-Project Potential to Emit[1,2]						Do Emissions from any Pollutant exceed 5 tons per year?
			CAPs						
			NO_X	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	
			tons/year						
108	Tank 153	Existing - Exempt	--	--	--	0.070	--	--	No
50007	Tank 224	Existing - Exempt	--	--	--	--	--	--	No
New/PTU	Wet Surface Air Cooler (WSAC)	New - Exempt	--	--	--	--	0.10	0.10	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 1	New - Exempt	--	--	--	0.028	--	--	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 2	New - Exempt	--	--	--	0.018	--	--	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 3	New - Exempt	--	--	--	0.028	--	--	No
New/PTU	Closed-Loop Vapor Recovery for FOG Recovery	New - Exempt	--	--	--	0.028	--	--	No
New/PTU	Dissolved Air Flotation Unit	New - Exempt	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400A)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400B)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400C)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400D)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400E)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400F)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400G)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400H)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400I)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400J)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400K)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Storage Silo (F-400L)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Filter Aid Storage Silo (F-401A)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401B)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401C)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401D)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401E)	New - Exempt	--	--	--	--	0.011	0.011	No
New/PTU	Filter Aid Storage Silo (F-401F)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401G)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401H)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Filter Aid Storage Silo (F-401I)	New - Exempt	--	--	--	--	0.031	0.031	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-502A)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper(F-502B)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526A)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526B)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Filter Aid Adsorption Day Hopper (F-527)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626A)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626B)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Filter Aid Adsorption Day Hopper (F-627)	New - Exempt	--	--	--	--	0.011	0.011	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-702A)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Polyethylene Removal Filter Aid Hopper (F-702B)	New - Exempt	--	--	--	--	0.041	0.041	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726A)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726B)	New - Exempt	--	--	--	--	0.081	0.081	No
New/PTU	Filter Aid Adsorption Day Hopper (F-727)	New - Exempt	--	--	--	--	0.041	0.041	No

Table 2
Determination of Source Exemption Status
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Comparison of Hazardous Pollutant Emissions to Requirements of 2-1-318

Source Number	Description[1,2,3]	Project Status	Post-Project Potential to Emit[3]								Do Emissions from any Pollutant exceed Single-Source Threshold?
			PSD Pollutant								
			Lead	Asbestos	Beryllium	Mercury	Vinyl Chloride	Fluorides	Sulfuric Acid Mist	Reduced Sulfur Compounds (inc. H_2S)	
			ton/year								
Single-Source Threshold (ton/year)			**0.60**	**0.0070**	**4.0E-04**	**0.10**	**1.0**	**3.0**	**7.0**	**10**	--
108	Tank 153	Existing - Exempt	--	--	--	--	--	--	--	--	No
50007	Tank 224	Existing - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Wet Surface Air Cooler (WSAC)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 1	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 2	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Closed-Loop Vapor Recovery for PTU Train 3	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Closed-Loop Vapor Recovery for FOG Recovery	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Dissolved Air Flotation Unit	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400C)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400D)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400E)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400F)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400G)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400H)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400I)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400J)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400K)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Storage Silo (F-400L)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401C)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401D)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401E)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401F)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401G)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401H)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Storage Silo (F-401I)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-502A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper(F-502B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Adsorption Day Hopper (F-527)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Adsorption Day Hopper (F-627)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-702A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Polyethylene Removal Filter Aid Hopper (F-702B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726A)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726B)	New - Exempt	--	--	--	--	--	--	--	--	No
New/PTU	Filter Aid Adsorption Day Hopper (F-727)	New - Exempt	--	--	--	--	--	--	--	--	No

Table 2
Determination of Source Exemption Status
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Comparison of TAC and HAP Emissions to Requirements of 2-1-316.1 and 2-1-316.2

Source	Description	Project Status	TAC	Baseline (2017-2019 Average)	Post-Project PTE	Net Change in Emissions		Acute Trigger Level	Chronic Trigger Level	Hourly Net Emission Rate Exceed Acute Trigger Level?	Annual Net Emission Rate Exceed Chronic Trigger Level?	HAP?	Exceed Single HAP Threshold of 2.5 tpy per Source?	Exceed Combined HAP Threshold of 6.25 tpy per Source?
				lb/yr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr					
108	Tank 153	Existing - Exempt	--	See Note	0	This source will not generate any TACs or HAPs post-project, thus any change from baseline will be negative and a comparison to trigger levels and HAP thresholds is not necessary								
50007	Tank 224	Existing - Exempt	--	See Note	0	This source will not generate any TACs or HAPs post-project, thus any change from baseline will be negative and a comparison to trigger levels and HAP thresholds is not necessary								
New/PTU	Wet Surface Air Cooler (WSAC)	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Closed-Loop Vapor Recovery for PTU Train 1	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Closed-Loop Vapor Recovery for PTU Train 2	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Closed-Loop Vapor Recovery for PTU Train 3	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Closed-Loop Vapor Recovery for FOG Recovery	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Dissolved Air Flotation Unit	New - Exempt	This source will not generate any TACs or HAPs.											
New/PTU	Bleaching Earth Storage Silo (F-400A)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400B)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400C)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400D)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400E)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400F)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400G)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400H)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400I)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400J)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400K)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Storage Silo (F-400L)	New - Exempt	Crystalline Silica	--	4.1	4.6E-04	4.1	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401A)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401B)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401C)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401D)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401E)	New - Exempt	Crystalline Silica	--	11	0.0012	11	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401F)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401G)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401H)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Filter Aid Storage Silo (F-401I)	New - Exempt	Crystalline Silica	--	31	0.0035	31	--	120	--	No	No	--	--
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-502A)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--
New/PTU	Polyethylene Removal Filter Aid Day Hopper(F-502B)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526A)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-526B)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Filter Aid Adsorption Day Hopper (F-527)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626A)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-626B)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Filter Aid Adsorption Day Hopper (F-627)	New - Exempt	Crystalline Silica	--	11	0.0012	11	--	120	--	No	No	--	--
New/PTU	Polyethylene Removal Filter Aid Day Hopper (F-702A)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--
New/PTU	Polyethylene Removal Filter Aid Hopper (F-702B)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726A)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Bleaching Earth Adsorption Day Hopper (F-726B)	New - Exempt	Crystalline Silica	--	8.1	9.2E-04	8.1	--	120	--	No	No	--	--
New/PTU	Filter Aid Adsorption Day Hopper (F-727)	New - Exempt	Crystalline Silica	--	41	0.0047	41	--	120	--	No	No	--	--

Notes:

1. Tank 153 and Tank 224 are exempt tanks and thus not subject to throughput limits. Instead, these tanks are subject to a mass emission limit of 5 tons per year in order to remain exempt per BAAQMD Regulation 2 Rule 1 Section 319.1. Thus, post-project actual emissions (as calculated in Stationary Source Table 11) are presented above rather than post-project potential to emit. Any potential emissions from Tank 224 would be reported as fugitive leaks.
2. Post-Project Potential to Emit for all new sources assumed to be equivalent to Post-Project Actual emission rates. Emissions calculations are presented in Stationary Source Tables 3 - 5.
3. Hazardous PSD pollutants will not be generated by any of the existing or new exempt sources.

Abbreviations:

CO - carbon monoxide
NOx - nitrogen oxides
PM_{10} - particulate matter less than 10 microns in diameter
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter
POC - precursor organic compounds
SO_2 - sulfur dioxide
yr - year

Table 3
Offsets Analysis for Existing and Proposed Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Description	Project Status	Baseline Emissions 2017-2019 Average (tons/year)[1]					Post-Project Potential to Emit (tons/year)[2]					Change in Emissions (tons/yr)				
			NO_X	**SO_2**	**POC**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**POC**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**POC**	**PM_{10}**	**$PM_{2.5}$**
109	Tank 154[4]	Contemporaneous	--	--	0.13	--	--	--	--	--	--	--	--	--	-0.13	--	--
439	Tank 109[4]	Contemporaneous	--	--	0.74	--	--	--	--	--	--	--	--	--	-0.74	--	--
442	Tank 112[4]	Contemporaneous	--	--	0.75	--	--	--	--	--	--	--	--	--	-0.75	--	--
29	Unit 200 B-5 Heater	Shutdown	11	18	1.6	2.1	2.1	--	--	--	--	--	-11	-18	-1.6	-2.1	-2.1
30	Unit 200 B-101 Heater	Shutdown	6.1	7.5	0.65	0.90	0.90	--	--	--	--	--	-6.1	-7.5	-0.65	-0.90	-0.90
36	Unit 200 B-102 Heater	Shutdown	1.5	1.5	0.87	1.2	1.2	--	--	--	--	--	-1.5	-1.5	-0.87	-1.2	-1.2
301	Molten Sulfur Pit 234	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
302	Molten Sulfur Pit 236	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
303	Molten Sulfur Pit 238	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
350	Unit 267 Crude Distillation Unit	Shutdown	--	--	3.4	--	--	--	--	--	--	--	--	--	-3.4	--	--
351	Unit 267 B-601/602 Tower Preheaters	Shutdown	4.1	17	1.5	2.0	2.0	--	--	--	--	--	-4.1	-17	-1.5	-2.0	-2.0
1002	Unit 236 Sulfur Plant	Shutdown	1.6	4.4	0.47	1.1	1.1	--	--	--	--	--	-1.6	-4.4	-0.47	-1.1	-1.1
1003	Unit 238 Sulfur Plant	Shutdown	4.0	5.5	0.20	1.1	1.1	--	--	--	--	--	-4.0	-5.5	-0.20	-1.1	-1.1
Plant ID 21360	Carbon Plant	Shutdown	364	1,349	0.23	23	21	--	--	--	--	--	-364	-1,349	-0.23	-23	-21
Plant ID 21360	Carbon Plant - Rail	Shutdown	0.24	0.0044	0.010	0.0045	0.0042	--	--	--	--	--	-0.24	-0.0044	-0.010	-0.0045	-0.0042
97	Tank 100	Altered	--	--	1.4	--	--	--	--	--	--	--	--	--	-1.4	--	--
50007	Tank 224	Existing - Exempt	--	--	2.9	--	--	--	--	--	--	--	--	--	-2.9	--	--
New/STU	U237 Sulfur Treatment Unit	New	--	--	--	--	--	25	8.8	0.34	6.4	6.4	25	8.8	0.34	6.4	6.4
New/PTU	Pretreatment Unit	New	--	--	--	--	--	--	--	3.3	--	--	--	--	3.3	--	--
--	OGV and Harbor Craft[3]	--	147	7.2	9.1	4.1	3.8	266	11	16	7.1	6.6	119	3.8	7.2	3.0	2.8
--	Rail[3]	--	1.3	0.027	0.046	0.027	0.025	2.6	0.083	0.082	0.042	0.039	1.2	0.057	0.036	0.015	0.014
Total:			**541**	**1,410**	**24**	**36**	**34**	**293**	**20**	**20**	**14**	**13**	**-247**	**-1,390**	**-3.8**	**-22**	**-21**

Notes:

[1] Baseline emissions for existing permitted sources obtained from Phillips 66's 2017, 2018, and 2019 R12-15 emissions inventories. Carbon Plant emissions are from BAAQMD Permit to Operate invoices. Details are shown in Stationary Source Table 6.

[2] Projected Actual emissions for new sources (assumed to be equal to Potential to Emit) are presented in Stationary Source Tables 1 and 2. Potential to Emit for Tank 100 is presented in Stationary Source Table 15. Projected Actual emissions for Tank 224 (Stationary Source Table 9) are shown rather than potential to emit since it is an exempt source and thus not subject to throughput limits. Further, any potential emissions from Tank 224 with Post-Project would be reported as fugitive leaks.

[3] Baseline emissions for OGV and Harbor Craft and Rail sources are for 2017-2019 activity. Note that there are baseline Rail emissions for both Rodeo and Carbon Plant sources.

[4] Three storage tanks (Tank 154, Tank 109, Tank 112) will be out of service and the reduction in their emissions will be used as contemporaneous offsets.

Abbreviations:

NOx - nitrogen oxides	POC - precursor organic compounds
PM_{10} - particulate matter less than 10 microns in diameter	SO_2 - sulfur dioxide
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter	yr - year

Table 4
PSD Analysis for Existing and Proposed Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Permitted Sources

Source Number	Description	Project Status	Post-Project Potential to Emit[1] (tons/year)						Change in Emissions (tons/yr)					
			NO$_X$	SO$_2$	CO	PM$_{10}$	Sulfuric Acid Mist	GHGs	NO$_X$	SO$_2$	CO	PM$_{10}$	Sulfuric Acid Mist	GHGs
New/STU	U237 Sulfur Treatment Unit	New	25	8.8	5.2	6.4	6.4	27,184	25	8.8	5.2	6.4	6.4	27,184
New/PTU	Pretreatment Unit	New	--	--	--	--	--	--	--	--	--	--	--	--
		Total:	**25**	**8.8**	**5.2**	**6.4**	**6.4**	**27,184**	**25**	**8.8**	**5.2**	**6.4**	**6.4**	**27,184**
BAAQMD PSD Review Significant Emissions Rate (ton/yr):									**40**	**40**	**100**	**15**	**7.0**	**75,000**
BAAQMD Attainment Status:									**A**	**A**	**A**	**U**	**--**	**--**
Are Increases in Total Net Emissions above Significant Emissions Rate?									**No**	**No**	**No**	**No**	**No**	**No**

Notes:

[1] Projected Actual emissions for new sources are presented in Stationary Sources Tables 1 and 2. U237 emits PM$_{10}$ as sulfuric acid mist so emissions are reported under both PM$_{10}$ and sulfuric acid pollutant thresholds.

Abbreviations:

CAPs - Criteria Air Pollutant
CO - carbon monoxide
CO$_2$e - carbon dioxide equivalents
GHGs - Greenhous Gases
MT - metric ton
NOx - nitrogen oxides
PM$_{10}$ - particulate matter less than 10 microns in diameter
PM$_{2.5}$ - particulate matter less than 2.5 microns in diameter
POC - precursor organic compounds
SO$_2$ - sulfur dioxide
yr - year

Table 5
Comparison to Rule 2-5 Thresholds for New and Modified Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Summary of TAC Emissions by Source[1]

Source	TAC	Baseline (2017-2019 Average)	Post-Project PTE	Net Change in PTE	
		lb/yr	lb/yr	lb/hr	lb/yr
U237 Sulfur Treatment Unit	Benzene	--	0.26	3.0E-05	0.26
	Formaldehyde	--	9.3	0.0011	9.3
	Toluene	--	0.42	4.8E-05	0.42
	Sulfuric Acid	--	12,800	1.5	12,800
Rail Locomotives[2]	DPM	13	21	8.4E-04	7.4
OGV Transiting (Main Engines)[3]	DPM	0.48	1.0	5.4E-05	0.48
Tug and Barge Transiting (Main Engines)[3]	DPM	1.4	2.8	1.5E-04	1.3
OGV Maneuvering (Main Engines)[3]	DPM	0.048	0.10	5.5E-06	0.048
Tug and Barge Maneuvering (Main Engines)[3]	DPM	1.6	3.0	1.7E-04	1.5
OGV Hoteling (Auxiliary Engines)[3]	DPM	1,529	2,030	0.057	501
Barge Hoteling (Auxiliary Engines)[3]	DPM	161	384	0.026	223
OGV Hoteling (Boiler)[3]	Arsenic	1.1E-04	1.5E-04	4.1E-09	3.6E-05
	Cadmium	1.6E-04	2.1E-04	5.9E-09	5.2E-05
	Copper	2.8E-04	3.7E-04	1.0E-08	9.1E-05
	Lead	0.0018	0.0023	6.6E-08	5.8E-04
	Nickel	0.040	0.053	1.5E-06	0.013
	Selenium	1.1E-04	1.5E-04	4.1E-09	3.6E-05
	Propylene	0.19	0.25	6.9E-06	0.061
	Hexane	0.065	0.086	2.4E-06	0.021
	Formaldehyde	0.0041	0.0054	1.5E-07	0.0013
	Xylenes	0.014	0.018	5.2E-07	0.0045
	Benzene	0.088	0.12	3.3E-06	0.029
	Toluene	0.087	0.12	3.3E-06	0.029
	Ethyl Benzene	0.0028	0.0038	1.1E-07	9.3E-04
	Xylene (o-)	0.013	0.017	4.7E-07	0.0041
	Xylene (m-)	0.018	0.024	6.8E-07	0.0060
	Chlorobenzene	0.0020	0.0027	7.6E-08	6.7E-04
	Naphthalene	0.028	0.038	1.1E-06	0.0093
	Vanadium	0.10	0.13	3.8E-06	0.033
	Sulfate	2.4	3.2	9.1E-05	0.80

Comparison of Total TAC Emissions to BAAQMD Regulation 2 Rule 5 Trigger Levels[4]

TAC	CAS	Net Change in PTE		Acute Trigger Level	Chronic Trigger Level	Hourly Net Emission Rate Exceed Acute Trigger Level?	Annual Net Emission Rate Exceed Chronic Trigger Level?
		lb/hr	lb/yr	lb/hr	lb/yr		
Arsenic	7440-38-2	4.1E-09	3.6E-05	4.4E-04	0.0016	No	No
Benzene	71-43-2	3.3E-05	0.29	0.060	2.9	No	No
Cadmium	7440-43-9	5.9E-09	5.2E-05	--	0.019	--	No
Chlorobenzene	108-90-7	7.6E-08	6.7E-04	--	39,000	--	No
Copper	7440-50-8	1.0E-08	9.1E-05	0.22	--	No	--
DPM	**--**	**0.084**	**735**	**--**	**0.26**	**--**	**Yes**
Ethyl Benzene	100-41-4	1.1E-07	9.3E-04	--	33	--	No
Formaldehyde	50-00-0	0.0011	9.3	0.12	14	No	No
Hexane	110-54-3	2.4E-06	0.021	--	270,000	--	No
Lead	7439-92-1	6.6E-08	5.8E-04	--	0.29	--	No
Naphthalene	91-20-3	1.1E-06	0.0093	--	2.4	--	No
Nickel	7440-02-0	1.5E-06	0.013	3.1E-05	0.31	No	No
Propylene	115-07-1	6.9E-06	0.061	--	120,000	--	No
Selenium	7782-49-2	4.1E-09	3.6E-05	--	8.0	--	No
Sulfate	--	9.1E-05	0.80	0.26	--	No	--
Sulfuric Acid	**7664-93-9**	**1.5**	**12,800**	**0.26**	**39**	**Yes**	**Yes**
Toluene	108-88-3	5.1E-05	0.45	82	12,000	No	No
Vanadium	7440-62-2	3.8E-06	0.033	0.066	--	No	--
Xylene (m-)	108-38-3	6.8E-07	0.0060	49	27,000	No	No
Xylene (o-)	95-47-6	4.7E-07	0.0041	49	27,000	No	No
Xylenes	1330-20-7	5.2E-07	0.0045	49	27,000	No	No

Notes:

[1] U237 Sulfur Treatment Unit emissions are presented in Stationary Source Table 1. Rail Locomotive emissions are presented in Rail Tables 14 - 17 for butane rail rack, Rail Tables 24 - 27 for carbon plant, and Rail Tables 34 - 37 for future refinery rail rack. Marine vessel emissions are presented in Marine Tables 1 - 3 for baseline emissions and Marine Tables 21 - 23 for future actual emissions.

[2] Total rail emissions were scaled to include only the emissions within the modeled area (8.3 miles/33.5 miles).

[3] Total OGV and Tug and Barge transiting PM_{10} emissions were scaled to include only emissions within the modeled area of 18.3 km. Maneuvering and hoteling emissions, which occur entirely within the BAAQMD boundary, were not scaled (e.g., a factor of one was applied). OGV and Harbor Craft transiting emissions in zones 1 through 4 were scaled down based on the one-way zone distance. All main and auxiliary engine PM_{10} emissions were assumed to be DPM. Boiler hoteling PM_{10} emissions were speciated into organic and metal TACs using a historical facility profile.

[4] Emissions were summed across all new and modified sources for comparison to BAAQMD Regulation 2 Rule 5 trigger levels. The only pollutants exceeding trigger levels are Diesel Particulate Matter (DPM), which exceeds the chronic trigger level and Sulfuric Acid, which exceeds both the acute and chronic trigger levels.

Abbreviations:

DPM - diesel particulate matter
hr - hour
lb - pound
PTE - potential to emit
TAC - Toxic Air Contaminant
yr - year

References:

BAAQMD. Regulation 2 Rule 5 Table 2-5-1 Toxic Air Contaminant Trigger Levels. Available online: https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-2-rule-5-new-source-review-of-toxic-air-contaminants/documents/rg0205_120716-pdf.pdf?la=en

Table 6
Design Analysis for SCR RACT Analysis
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Parameter	Description	Value	Units	Notes
Q_B	Heat input rate	14.8	MMBtu/hr	
CF	Capacity factor	1.0	--	Year-round operation
h_{NOx}	NO_x removal efficiency	90%	--	
$q_{fluegas}$	Flue gas flow rate	5,291	cu ft/min	Vendor data
$Vol_{catalyst}$	Volume of catalyst	50.3	cu ft	
h_{adj}	NO_x efficiency adjustment factor	1.24	--	
$Slip_{adj}$	Ammonia slip adjustment factor	1.0	--	assume 5 ppm slip
NOx_{adj}	Inlet NO_x adjustment factor	0.98	--	
NOx_{in}	Uncontrolled NO_x in flue gas	0.38	lb/MMBtu	
S_{adj}	Sulfur in coal adjustment factor	1.0	--	Only relevant for units fired on coal
T_{adj}	Temperature adjustment factor	1.0	--	assume reactor inlet temp of 700 deg F
$A_{catalyst}$	Catalyst cross-sectional area	6	sq ft	
n_{layer}	Number of catalyst layers	3	--	
n_{total}	Total catalyst layers (including empty layers)	3	--	
h_{layer}	Height of one catalyst layer	4.1	ft	
h_{SCR}	Height of SCR reactor	42.3	ft	
DP_{duct}	Pressure drop (duct)	2	in H_2O	
$DP_{catalyst}$	Pressure drop (catalyst)	0.75	in H_2O	
$m_{reagent}$	Mass flow of reagent	7.0	lb/hr	Assume urea as reagent
m_{sol}	Mass flow of aqueous reagent solution	14	lb/hr	
C_{sol}	Urea concentration by weight	50%	--	
q_{sol}	Solution volume flow rate	0.20	gal/hr	
TV	Tank volume for reagent storage	1,000	gallons	

Reference:

USEPA, "EPA Air Pollution Control Cost Manual, 7th Edition," EPA-452-02-001, 2002.

Table 7
Cost Analysis for SCR RACT Analysis
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Installed Capital Costs		
SCR duct, catalyst, ammonia vaporization skid, and aqueous ammonia storage	$7,400,000	Vendor quote
Direct Annual Costs		
Operating and Supervisory Labor	$0	
Maintenance Labor (0.015 installed capital cost)	$111,000	
Annual Reagent Consumption Cost	$36,480	
Ammonia volume flow rate	14	lb/hr
Ammonia reagent cost	$0.30	$/lb
Capacity factor	1.0	--
Annual Electricity Cost	$3,362	
Heat input rate	14.8	MMBtu/hr
Input NO_x concentration	0.38	lb/MMBtu
NO_x removal efficiency	90%	--
Pressure drop (duct)	2	in H_2O
Number of catalyst layers	3	--
Pressure drop (catalyst)	0.75	in H_2O
Capacity factor	1.0	--
Electricity cost	$0.10	$/kWh
Annual Catalyst Replacement Cost	$0.01	
Catalyst volume	50.3	cu ft
Catalyst cost	$240	$/cu ft
Catalyst replacement factor (R_{layer})	1	
Catalyst operating life	8,760	hours
Term of FWF	175.2	years
Future Worth Factor (FWF)	0.00	--
Subtotal (DAC)	$147,480	
Indirect Annual Costs (TCI x CRF)	$1,005,423	
Capital Recovery Factor (6% over 10 years)	0.136	
Total Annual Costs (TAC)	**$1,152,903**	
Uncontrolled NO_x emissions	25	tons/yr
Removal efficiency	90%	
Controlled NO_x emissions	2.5	tons/yr
Annual NO_x removed	22.3	tons/yr
Cost Effectiveness	**$51,612**	**$/ton NOx**
BAAQMD NOx cost effectiveness threshold	**$17,500**	**$/ton NOx**

Reference:

USEPA, "EPA Air Pollution Control Cost Manual, 7th Edition," EPA-452-02-001, 2002.

Table 8
Federal Major Modification Analysis for Existing and Proposed Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Permitted Sources

			Baseline Emissions 2018-2019 Average (tons/year)[1]											Projected Actuals (tons/year)[2]											Change in Emissions (tons/yr)										
Source Number	**Description**	**Project Status**	**NO$_X$**	**SO$_2$**	**CO**	**POC**	**PM (total)**	**PM$_{10}$**	**PM$_{2.5}$**	**Mercury**	**Sulfuric Acid Mist**	**Reduced Sulfur Compounds (inc. H2S)**	**GHGs**	**NO$_X$**	**SO$_2$**	**CO**	**POC**	**PM (total)**	**PM$_{10}$**	**PM$_{2.5}$**	**Mercury**	**Sulfuric Acid Mist**	**Reduced Sulfur Compounds (inc. H_2S)**	**GHGs**	**NO$_X$**	**SO$_2$**	**CO**	**POC**	**PM (total)**	**PM$_{10}$**	**PM$_{2.5}$**	**Mercury**	**Sulfuric Acid Mist**	**Reduced Sulfur Compounds (inc. H_2S)**	**GHGs**
97	Tank 100	Altered	--	--	--	1.4	--	--	--	1.8E-10	--	0.017	3.4	--	--	--	--	--	--	--	--	--	--	--	--	--	--	-1.4	--	--	--	-1.8E-10	--	-0.017	-3.4
307	U240 Unicracking Unit	Altered	--	--	--	4.2	--	--	--	--	--	0.020	--	--	--	--	4.9	--	--	--	--	--	0.020	--	--	--	--	0.61	--	--	--	--	--	1.7E-04	--
334	Tank 107	Altered	--	--	--	0.85	--	--	--	1.7E-10	--	0.010	2.4	--	--	--	0.24	--	--	--	--	--	--	--	--	--	--	-0.61	--	--	--	-1.7E-10	--	-0.010	-2.4
440	Tank 110	Altered	--	--	--	0.72	--	--	--	--	--	--	0.94	--	--	--	2.3	--	--	--	--	--	--	--	--	--	--	1.6	--	--	--	--	--	--	-0.94
New/STU	U237 Sulfur Treatment Unit	New	--	--	--	--	--	--	--	--	--	--	--	25	8.8	5.2	0.34	6.4	6.4	6.4	--	6.4	--	27,184	25	8.8	5.2	0.34	6.4	6.4	6.4	--	6.4	--	27,184
New/PTU	Pretreatment Unit	New	--	--	--	--	--	--	--	--	--	--	--	--	--	--	3.3	--	--	--	--	--	--	--	--	--	--	3.3	--	--	--	--	--	--	--
		Total:	**--**	**--**	**--**	**7.2**	**--**	**--**	**--**	**3.5E-10**	**--**	**0.048**	**6.7**	**25**	**8.8**	**5.2**	**11**	**6.4**	**6.4**	**6.4**	**--**	**6.4**	**0.020**	**27,184**	**25**	**8.8**	**5.2**	**3.8**	**6.4**	**6.4**	**6.4**	**-3.5E-10**	**6.4**	**-0.028**	**27,177**
Federal Major Modification Significant Emissions Rate (ton/yr):																									**40**	**40**	**100**	**40**	**25**	**15**	**10**	**0.10**	**7.0**	**10**	**75,000**
BAAQMD Attainment Status:																									**A**	**A**	**A**	**N**	**--**	**U**	**N**	**--**	**--**	**--**	**--**
Are Increases in Total Net Emissions above Significant Emissions Rate?																									**No**	**No**	**No**	**No**	**No**	**No**	**No**	**N/A**	**No**	**N/A**	**No**

Notes:

[1] Baseline emissions obtained from Phillips 66's 2018 and 2019 R12-15 emissions inventories. Details are shown in Stationary Source Table 6.

[2] Projected actual emissions are presented in Stationary Source Table 1 and 2 for new sources, Stationary Source Tables 7 and 8 for U240, and Stationary Source Table 14 for existing tanks.

Abbreviations:

CAPs - Criteria Air Pollutant
CO - carbon monoxide
CO$_2$e - carbon dioxide equivalents
GHGs - Greenhouse Gases
MT - metric ton
NOx - nitrogen oxides
PM$_{10}$ - particulate matter less than 10 microns in diameter
PM$_{2.5}$ - particulate matter less than 2.5 microns in diameter
POC - precursor organic compounds
SO$_2$ - sulfur dioxide
yr - year

APPENDIX A
BAAQMD APPLICATION FORMS

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

Form P-101B
Authority to Construct/
Permit to Operate

1. Application Information

BAAQMD Plant No. A0016 Company Name Phillips 66 Company

Equipment/Project Description Rodeo Renewed Project/Process Renewable Feedstocks to Produce Renewable Fuels

2. Plant Information *If you have not previously been assigned a Plant Number by the District or if you want to update any plant data that you have previously supplied to the District, please complete this section.*

Equipment Location

City Zip Code

Mail Address

City State Zip Code

Plant Contact Title

Telephone ( ) Fax ( ) Email

NAICS (North American Industry Classification System) see www.census.gov/epcd/naics02/naico602.htm 325199

3. Proximity to a School (K-12)

The sources in this permit application (*check one*) ☐ Are ☒ Are not within 1,000 ft of the outer boundary of the nearest school.

4. Application Contact Information *All correspondence from the District regarding this application will be sent to the plant contact unless you wish to designate a different contact for this application.*

Application Contact Wilma Dreessen Title Senior Environmental Consultant

Mail Address 1380 San Pablo Ave.

City Rodeo State CA Zip Code 94572

Telephone (510) 245-5893 Fax (510) 245-4512 Email Wilma.J.Dreessen@P66.com

5. Additional Information *The following additional information is required for all permit applications and should be included with your submittal. Failure to provide this information may delay the review of your application. Please indicate that each item has been addressed by checking the box. Contact the Engineering Division if you need assistance.*

☐ If a new Plant, a local street map showing the location of your business

☒ A facility map, drawn roughly to scale, that locates the equipment and its emission points

☒ Completed data form(s) and a pollutant flow diagram for each piece of equipment.
(See www.baaqmd.gov/Forms/Engineering.aspx)

☒ Project/equipment description, manufacturer's data

☒ Discussion and/or calculations of the emissions of air pollutants from the equipment

6. Trade Secrets *Under the California Public Records Act, all information in your permit application will be considered a matter of public record and may be disclosed to a third party. If you wish to keep certain items separate as specified in Regulation 2, Rule 1, Section 202.7, please complete the following steps.*

☐ Each page containing trade secret information must be labeled "trade secret" with the trade secret information clearly marked.

☐ A second copy, with trade secret information blanked out, marked "public copy" must be provided.

☐ For each item asserted to be trade secret, you must provide a statement which provides the basis for your claim.

7. Small Business Certification *You are entitled to a reduced permit fee if you qualify as a small business as defined in Regulation 3. In order to qualify, you must certify that your business meets all of the following criteria:*

☐ The business does not employ more than 10 persons and its gross annual income does not exceed $600,000.

☐ And the business is not an affiliate of a non-small business. (Note: a non-small business employs more than 10 persons and/or its gross income exceeds $600,000.)

8. Accelerated Permitting *The Accelerated Permitting Program entitles you to install and operate qualifying sources of air pollution and abatement equipment* ***without waiting for the District to issue a Permit to Operate****. To participate in this program you must certify that your project will meet all of the following criteria. Please acknowledge each item by checking each box.*

☐ Uncontrolled emissions of any single pollutant are each less than 10 lb/highest day, or the equipment has been precertified by the BAAQMD.

☐ Emissions of toxic compounds do not exceed the trigger levels identified in Table 2-5-1 (see Regulation 2, Rule 5).

☐ The project is not subject to public notice requirements (the source is either more than 1000 ft. from the nearest school, or the source does not emit any toxic compound in Table 2-5-1).

☐ For replacement of abatement equipment, the new equipment must have an equal or greater overall abatement efficiency for all pollutants than the equipment being replaced.

☐ For alterations of existing sources, for all pollutants the alteration does not result in an increase in emissions.

☐ Payment of applicable fees (the minimum permit fee to install and operate each source). See Regulation 3 or contact the Engineering Division for help in determining your fees.

9. CEQA *Please answer the following questions pertaining to CEQA (California Environmental Quality Act).*

A. Has another public agency prepared, required preparation of, or issued a notice regarding preparation of a California Environmental Quality Act (CEQA) document (initial study, negative declaration, environmental impact report, or other CEQA document) that analyzes impacts of this project or another project of which it is a part or to which it is related? ☒ YES ☐ NO If no, go to section 9B.

Describe the document or notice, preparer, and date of document or expected date of completion:

Contra Costa County Notice of Preparation of a Draft Environmental Impact Report January 21, 2021

Contra Costa County Draft Environmental Impact Report

B. List and describe any other permits or agency approvals required for this project by city, regional, state or federal agencies:

C. List and describe all other prior or current projects for which either of the following statements is true: (1) the project that is the subject of this application could not be undertaken without the project listed below, (2) the project listed below could not be undertaken without the project that is the subject of this application:

None

10. Certification *I hereby certify that all information contained herein is true and correct. (Please sign and date this form)*

Wilma J. Dreessen	Sr. Env. Consultant	Wilma J. Dreessen	5/19/2021
Name of person certifying (print)	Title of person certifying	Signature of person certifying	Date

Send all application materials to the **BAAQMD Engineering Division, 939 Ellis Street, San Francisco, CA 94109.**

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Rodeo Facility Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ________
3. Name or Description: Sulfur Treatment Unit Source No.: S- NEW
4. Make, Model, and Rated Capacity of Equipment: Custom
5. Process Code[1] 7999 Material Code[2] 189 Usage Unit[2] cubic feet
6. Total throughput, last 12 mos. ________usage units[2] Maximum operating rate: 30,000 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ________ minutes/cycle ________ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 4000 cfm at 155 °F
Approximate water vapor content 27.5 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate	0.00073	
12. Organics		
13. Nitrogen Oxides (as NO_2)	0.00283	
14, Sulfur Dioxide	0.00014	4
15. Carbon Monoxide		
16. Other: Sulfuric acid mist	0.00014	
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ________ **S-** ________ **S-** ________ **A** New Thermal Oxidizer **A-** New Caustic Scrubber **A-** ________
P- New Stack **P-** ________ **P-** ________ **P-** ________ **P-** ________

[1]See Tables G-1 through G-7 for code
[3]See Basis Code Table below
[2]See Table G5 or the Material Codes Table (available upon request)

Person completing this form: Wilma Dreessen Date: 5/1/2021

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
375 Beale Street, Suite 600, San Francisco, CA 94105
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

Data Form C
Fuel Combustion Source

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form

. ☒ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form

Company Name: Phillips 66 Company Plant No: A0016 Source No.*: NEW
Equipment Name & Number, or Description: Thermal Oxidizer at STU (Typical of two)
Make, Model: TBD Maximum firing rate: 7.4 MMBtu/hr
Date of modification or initial operation: ______ *(if unknown, leave blank)*

Primary Use: ☐ Electrical Generation ☐ Space Heat ☐ Waste Disposal ☐ Testing
☒ Abatement Device ☐ Cogeneration ☐ Resource Recovery ☐ Other
☐ Process heater; material heated:

SIC Number: *2869*

Equipment Type (Check one)

Internal Combustion Use Form ICE (Internal Combustion Engines) unless it is a gas turbine
☐ gas turbine ________ hp
☐ Other ____________ hp

Incinerator ☐ Salvage Operation ☐ Pathological Waste Temperature °F
☐ Liquid Waste ☐ Other ____________ Residence Time Sec

Others ☐ Boiler ☐ Dryer
☐ Afterburner ☐ Oven
☐ Flare ☐ Furnace Material dried, baked, or heated:
☐ Open Burning ☐ Kiln
☒ Other Thermal Oxidizer

Overfire air? ☐ Yes ☒ No If yes, what percent ________ %
Flue gas recirculation? ☐ Yes ☒ No If yes, what percent ________ %
Air pre-heat? ☐ Yes ☒ No Temperature ________ °F
Low NO_x burners? ☒ Yes ☐ No Make, Model TBD
Maximum flame temperature _____ °F
Combustion products: Wet gas flowrate 4,000 acfm at 155 °F
Typical Oxygen Content ____ dry volume % or 27.5 wet volume % Or _____ % excess air
Typical Use: 24 Hours/day 7 Days/week 52 Weeks/yr

Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %

With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?

S STU S _____ S _____ S _____ A _____ A _____ A _____ A _____

With regard to air pollutant flow, what source(s) or abatement device(s) are immediately DOWNSTREAM?

S _____ S _____ S _____ S _____ A Scrub A _____ P STU P _____

Person completing this form: Wilma Dreessen Date: 5/1/2021

(*revised 4/12/16*)

FUELS

INSTRUCTIONS Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable.

Section A: Fuel Data

	Fuel Name	***Fuel Code***	***Total Annual Usage***	***Maximum Possible Fuel Use Rate***	***Typical Heat Content***	***Sulfur Content***	***Nitrogen Content (Optional)***	***Ash Content (Optional)***
1	Natural Gas	189		7.4 MM	1050			
2								
3								
4								

Use the appropriate units for each fuel	Natural Gas	Therm	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF	MSCF/hr	Btu/MSCF	Ppm	N/A	N/A
	Liquid	M gal	M gal /hr	Btu/m gal	Wt%	Wt%	Wt%
	Solid	ton	Ton/hr	Btu/ton	Wt%	Wt%	Wt%

Section B: Emission Factors (Optional)

	Fuel Name	***Fuel Code***	***Particulates***		***NOx***		***CO***	
			Emission Factor	*Basis Code*	*Emission Factor*	*Basis Code*	*Emission Factor*	*Basis Code*
1								
2								
3								
4								

Use the appropriate units for each fuel	Natural Gas	Lb/Therm
	Other Gas	Lb/MSCF
	Liquid	Lb/M gal
	Solid	Lb/ton

Note: * MSCF = thousand standard cubic feet

** m gal = thousand gallons

*** See tables below for Fuel and Basis Codes

**** Total annual usage is: -Projected usage over next 12 months if equipment is new or modified

\- Actual usage for last 12 months if equipment is existing and unchanged

Fuels Codes				***Basis Codes***	
Code	***Fuel***	***Code***	***Fuel***	***Code***	***Method***
25	Anthracite coal	189	Natural gas	0	Not applicable for this pollutant
33	Bagasse	234	Process gas – blast furnace	1	Source testing or other measurement by plant (attach copy)
35	Bark	235	Process gas – CO	2	Source testing or other measurement by BAAQMD (give date)
43	Bituminous Coal	236	Process gas – coke oven gas	3	Specifications from vendor (attach copy)
47	Brown Coal	238	Process gas – RMG	4	Material balance by plant using engineering expertise and knowledge of process
242	Bunker C fuel oil	237	Process gas – other	5	Material balance by BAAQMD
80	Coke	242	Residual Oil	6	Taken from AP-42
89	Crude Oil	495	Refuse derived fuel	7	Taken from literature, other than AP-42
98	Diesel oil	511	Landfill gas	8	Guess
493	Digester gas	256	Solid propellant		
315	Distillate oil	466	Solid waste		
392	Fuel Oil #2	304	Wood – hogged		
551	Gasoline	305	Wood – other		
158	Jet fuel	198	Other – gaseous fuels		
160	LPG	200	Other – liquid fuels		
165	Lignite	203	Other – solid fuels		
167	Liquid waste				
494	Municipal solid waste				

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description Scrubber (Typical of two) Abatement Device No: A- NEW
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 46 and 44 Date of Initial Operation ____
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- STU S- ____ S- ____ S- ____ S- ____
S- ____ A- TO A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 155 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide	99+	4
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- ____ A- ____ A- ____ P- STU P- ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company

Plant No: A0016

Emission Point No: P- STU (2)

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S-	STU	**S-**		**S-**		**S-**		**S-**			
S-		**A-**	TO	**A-**	Scrubber	**A-**		**A-**		**A-**	

Exit cross-section area: 1.79 sq. ft.

Height above grade: 120 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	3000 cfm	4000 cfm
Percent Water Vapor	27.5 Vol %	27.5 Vol %
Temperature	116 °F	116 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored?

Person completing this form Wilma Dreessen

Date 4/29/2021

Form HRA

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
375 Beale Street, Suite 600, San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

Health Risk Assessment

IMPORTANT: For any permit application that requires a Health Risk Assessment, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Phillips 66 Company Rodeo Facility Plant No.: A0016

Source Description: Sulfur Treatment Unit

Source No.: S-New (if known) Emission Point No.: P-New (Typical of two stacks) (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☒ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☒ alone OR ☐ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 120 feet OR _______ meters?
4. What is the inside diameter of the stack outlet? 18 inches OR _______ feet OR _______ meters
5. What is the direction of the exhaust from the stack outlet? ☐ horizontal OR ☒ vertical
6. Is the stack outlet: ☒ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 3000 cfm (cubic feet/min) OR _______ meters^3/second
8. What is the typical temperature of the exhaust gas? 155 degrees Fahrenheit OR _______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

   ____

   ____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2						
B3						
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

____

____

____

____

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):

   ☐ zoned for residential use
   ☐ zoned for mixed residential and commercial/industrial use
   ☒ zoned for commercial and/or industrial use
   ☐ zoned for agricultural use

2. Distance from source (stack or building) to nearest facility property line = ______ feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = ______ feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☐ Industrial/Commercial OR ☐ Other _______________

   ____

5. Distance from source (stack or building) to property line of nearest nonresidential site = ______ feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☒ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   ____

   ____

*K-12 and more than twelve children only

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ________
3. Name or Description: Pretreatment Unit Source No.: S- New
4. Make, Model, and Rated Capacity of Equipment: Alfa Laval, or equivalent
5. Process Code[1] 7999 Material Code[2] 509, 351 Usage Unit[2] thou gallons
6. Total throughput, last 12 mos. ______usage units[2] Maximum operating rate:______usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate ______ cfm at ______ °F
Approximate water vapor content ______ volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☐ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics		
13. Nitrogen Oxides (as $N0_2$)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:______		
17. Other:______		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** ______ **A-** ______ **A-** ______
P- ______ **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1] **See Tables G-1 through G-7 for code**
[2] **See Table G5 or the Material Codes Table (available upon request)**
[3] **See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: PTU Closed Loop Vapor Recovery Train 1 Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5. Process Code[1] 8999 Material Code[2] 504 Usage Unit[2] cubic feet
6. Total throughput, last 12 mos. ______usage units[2] Maximum operating rate: 41648 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 1860 cfm at 70 °F
Approximate water vapor content 0.062 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics	0.00000015	4
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** Biofilter 1 **A-** Carbon 1 **A-** ______
P- PTU 1 **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1] **See Tables G-1 through G-7 for code**
[2] **See Table G5 or the Material Codes Table (available upon request)**
[3] **See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU Biofilter 1 Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 64 Date of Initial Operation ________
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 1 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** Carbon 1 **A-** ____ **A-** ____ **P-** PTU 1 **P-** ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU 1 Carbon Adsorption Abatement Device No: A- New
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 56 Date of Initial Operation ______
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 1 **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** Biofilter 1 **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	99.5	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** ______ **A-** ______ **A-** ______ **P-** PTU 1 **P-** ______

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA. . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company

Plant No: A0016

Emission Point No: P-PTU 1

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 1 **S-** ___ **S-** ___ **S-** ___ **S-** ___
S- ___ **A-** Biofilter **A-** Carbon **A-** ___ **A-** ___ **A-** ___

Exit cross-section area: 1.4 sq. ft.

Height above grade: 10.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	1860 cfm	1860 cfm
Percent Water Vapor	0.062 Vol %	0.062 Vol %
Temperature	70 °F	70 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ___

Person completing this form Wilma Dreessen

Date 5/1/2021

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DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ________
3. Name or Description: PTU Closed Loop Vapor Recovery Train 2 Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5. Process Code[1] 8999 Material Code[2] 504 Usage Unit[2] cubic feet
6. Total throughput, last 12 mos. ________ usage units[2] Maximum operating rate: 26976 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ________ minutes/cycle ________ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 1860 cfm at 70 °F
Approximate water vapor content 0.062 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics	0.00000015	4
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ____ **S-** ____ **S-** ____ **A** Biofilter 2 **A-** Carbon 2 **A-** ____
P- PTU 2 **P-** ____ **P-** ____ **P-** ____ **P-** ____

---

[1] **See Tables G-1 through G-7 for code**
[2] **See Table G5 or the Material Codes Table (available upon request)**
[3] **See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU Biofilter 2 Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 64 Date of Initial Operation ____
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 2 S- ____ S- ____ S- ____ S- ____
S- ____ A- ____ A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- Carbon 2 A- ____ A- ____ P- PTU 2 P- ____

Person completing this form: Wilma J. Dressen Date: 05/01/2021

(revised 5/18)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU 2 Carbon Adsorption Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 56 Date of Initial Operation
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 2 **S-** **S-** **S-** **S-**
S- **A-** Biofilter 2 **A-** **A-** **A-** **A-**

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	99.5	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- **A-** **A-** **A-** **P-** PTU 2 **P-**

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA. . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company Plant No: A0016

Emission Point No: P-PTU 2

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S-	PTU 2	**S-**		**S-**		**S-**		**S-**			
S-		**A-**	Biofilter	**A-**	Carbon	**A-**		**A-**		**A-**	

Exit cross-section area: 1.4 sq. ft. Height above grade: 10.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	1860 cfm	1860 cfm
Percent Water Vapor	0.062 Vol %	0.062 Vol %
Temperature	70 °F	70 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ____________

Person completing this form Wilma Dreessen Date 5/1/2021

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: PTU Closed Loop Vapor Recovery Train 3 Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5. Process Code[1] 8999 Material Code[2] 504 Usage Unit[2] cubic feet
6. Total throughput, last 12 mos. ______ usage units[2] Maximum operating rate: 41648 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 1860 cfm at 70 °F
Approximate water vapor content 0.062 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics	0.00000015	4
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** Biofilter 3 **A-** Carbon 3 **A-** ______
P- PTU 3 **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1] See Tables G-1 through G-7 for code
[2] See Table G5 or the Material Codes Table (available upon request)
[3] See Basis Code Table below

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)

2. Name or Description PTU Biofilter 3 Abatement Device No: A- New/Exem

3. Make, Model, and Rated Capacity TBD

4. Abatement Device Code (See table*) 64 Date of Initial Operation ________

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 3 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	**Weight Percent Reduction (at typical operation)**	**Basis Codes** *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** Carbon 3 **A-** ____ **A-** ____ **P-** PTU 3 **P-** ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU 3 Carbon Adsorption Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 56 Date of Initial Operation ________
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU 3 S- ____ S- ____ S- ____ S- ____
S- ____ A- Biofilter 3 A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	99.5	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- ____ A- ____ A- ____ P- PTU 3 P- ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company Plant No: A0016

Emission Point No: P-PTU 3

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S-	PTU 3	**S-**		**S-**		**S-**		**S-**			
S-		**A-**	Biofilter	**A-**	Carbon	**A-**		**A-**		**A-**	

Exit cross-section area: 1.4 sq. ft. Height above grade: 10.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1860 cfm	1860 cfm
Percent Water Vapor	0.062 Vol %	0.062 Vol %
Temperature	70 °F	70 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ____________________

Person completing this form Wilma Dreessen Date 5/1/2021

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016
2. SIC No.: 2869 Date of Initial Operation ____________ (if unknown, leave blank)
3. Name or Description: PTU Closed Loop Vapor Recovery FOG Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5. Process Code[1] 8999 Material Code[2] 504 Usage Unit[2] cubic feet
6. Total throughput, last 12 mos. ________usage units[2] Maximum operating rate: 41648 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ________ minutes/cycle ________ minutes between cycles
10. Exhaust gases from source: (at maximum operation) Wet gas flowrate 1860 cfm at 70 °F
    Approximate water vapor content 0.062 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics	0.00000015	4
13. Nitrogen Oxides (as $N0_2$)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other: ____________		
17. Other: ____________		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ________ **S-** ________ **S-** ________ **A** Biofilter FOG **A-** Carbon FOG **A-** ________
P- PTU FOG **P-** ________ **P-** ________ **P-** ________ **P-** ________

[1]See Tables G-1 through G-7 for code **[2]See Table G5 or the Material Codes Table (available upon request)**
[3]See Basis Code Table below

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU Biofilter FOG Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 64 Date of Initial Operation ________
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU FOG S- ____ S- ____ S- ____ S- ____
S- ____ A- ____ A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- Carbon FOG A- ____ A- ____ P- PTU FOG P- ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description PTU FOG Carbon Adsorption Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 56 Date of Initial Operation ________
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- PTU FOG **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** Biofilter FOG **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	99.5	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** ______ **A-** ______ **A-** ______ **P-** PTU FOG **P-** ______

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company

Plant No: A0016

Emission Point No: P-PTU FOG

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S-	PTU FOG	**S-**		**S-**		**S-**		**S-**			
S-		**A-**	Biofilter	**A-**	Carbon	**A-**		**A-**		**A-**	

Exit cross-section area: 1.4 sq. ft.

Height above grade: 10.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	1860 cfm	1860 cfm
Percent Water Vapor	0.062 Vol %	0.062 Vol %
Temperature	70 °F	70 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored?

Person completing this form Wilma Dreessen

Date 5/1/2021

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: PTU Dissolved Air Flotation Unit Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5. Process Code[1] 8999 Material Code[2] 503 Usage Unit[2] thou gal
6. Total throughput, last 12 mos. ______ usage units[2] Maximum operating rate: 15 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate ______ cfm at ______ °F
Approximate water vapor content ______ volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics	0	4
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other: ______		
17. Other: ______		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- PTU FOG Vapor **S-** ______ **S-** ______ **A** biofilter **A-** carbon **A-** ______
P- PTU FOG Vapor **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1]**See Tables G-1 through G-7 for code** [2]**See Table G5 or the Material Codes Table (available upon request)**
[3]**See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: Wet Surface Air Cooler (WSAC) Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: Alfa Laval Niagra 8,000 gpm, or equivalent
5. Process Code[1] 7106 Material Code[2] 415 Usage Unit[2] thou gal
6. Total throughput, last 12 mos. ______ usage units[2] Maximum operating rate: 480 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 216,308 cfm at 81.5 °F
Approximate water vapor content 0.00003 volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☐ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate	0.0000474	3,4
12. Organics		
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** ______ **A-** ______ **A-** ______
P- WSAC **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1] **See Tables G-1 through G-7 for code**
[2] **See Table G5 or the Material Codes Table (available upon request)**
[3] **See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company Plant No: A0016

Emission Point No: P- WSAC

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- WSAC **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 153.9 sq. ft. Height above grade: 25.8 ft.

Effluent Flow from Stack

	Typical Operating Condition		*Maximum Operating Condition*	
Actual Wet Gas Flowrate	216,308	cfm	216,308	cfm
Percent Water Vapor	0.00003	Vol %	0.00003	Vol %
Temperature	81.5	°F	81.5	°F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ____

Person completing this form Wilma Dreessen Date 5/1/20216

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ____
3. Name or Description: Silo (typical of 21) Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: Belgrade 1200 BBL, or equivalent
5. Process Code[1] 7014 Material Code[2] 72, 97 Usage Unit[2] tons
6. Total throughput, last 12 mos. ____ usage units[2] Maximum operating rate: 2.1 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ____ minutes/cycle ____ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 1600 cfm at 122 °F
Approximate water vapor content ____ volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

▣ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate	0.033	3
12. Organics		
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ____ **S-** ____ **S-** ____ **A** Silo **A-** ____ **A-** ____
P- Silo **P-** ____ **P-** ____ **P-** ____ **P-** ____

[1] **See Tables G-1 through G-7 for code**
[3] **See Basis Code Table below**
[2] **See Table G5 or the Material Codes Table (available upon request)**

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description Dust Filter for Silo (typical of 21) Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity Belgrade 330 Pulse Jet Dust House, 1600 SCFM, or equivalent
4. Abatement Device Code (See table*) 8 Date of Initial Operation ______
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- Silo S- ____ S- ____ S- ____ S- ____
S- ____ A- ____ A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 122 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	99.97% for particles < 1 micron. Control efficiency is 100% for particles > 1 micron	3
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- ____ A- ____ A- ____ P- Silo P- ____

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA. . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company

Plant No: A0016

Emission Point No: P-Silo

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- Silo **S-** ____ **S-** ____ **S-** ____ **S-** ____

S- ____ **A-** Silo **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 0.546 sq. ft.

Height above grade: 73.8 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1600 cfm	1600 cfm
Percent Water Vapor	Vol %	Vol %
Temperature	122 °F	122 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored? ____

Person completing this form Wilma Dreessen

Date 5/1/2021

Form HRA

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

Health Risk Assessment

IMPORTANT: For any permit application that requires a Health Risk Assessment, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Phillips 66 Company Rodeo Facility Plant No.: A0016

Source Description: Silo (typical of 21)

Source No.: S- New/Exempt (if known) Emission Point No.: P- New/Exempt (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ■ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ■ alone OR ☐ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 73.8 feet OR _______ meters?
4. What is the inside diameter of the stack outlet? _______ inches OR 0.834 feet OR _______ meters
5. What is the direction of the exhaust from the stack outlet? ☐ horizontal OR ■ vertical
6. Is the stack outlet: ■ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 1600 cfm (cubic feet/min) OR _______ meters^3/second
8. What is the typical temperature of the exhaust gas? 122 degrees Fahrenheit OR _______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

____

____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2						
B3						
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

____

____

____

____

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   ☐ zoned for residential use
   ☐ zoned for mixed residential and commercial/industrial use
   ☒ zoned for commercial and/or industrial use
   ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = ______ feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = ______ feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☐ Industrial/Commercial OR ☐ Other ______________

   ____
5. Distance from source (stack or building) to property line of nearest nonresidential site = ______ feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☒ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   ____

   ____

*K-12 and more than twelve children only

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: Day Hopper (typical of 13) Source No.: S- New/Exempt
4. Make, Model, and Rated Capacity of Equipment: TBD
5 Process Code[1] 7014 Material Code[2] 72, 97 Usage Unit[2] tons
6. Total throughput, last 12 mos. ______ usage units[2] Maximum operating rate: 2.1 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate 486 cfm at 122 °F
Approximate water vapor content ______ volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☒ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate	0.033	3
12. Organics		
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** Day Hopper **A-** ______ **A-** ______
P- Day Hopper **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1]See Tables G-1 through G-7 for code **[2]See Table G5 or the Material Codes Table (available upon request)**
[3]See Basis Code Table below

Person completing this form: Wilma Dreessen Date: 5/1/2021

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description Dust Filter for Day Hoppers (typical of 13) Abatement Device No: A- New/Exem
3. Make, Model, and Rated Capacity Kice Model VR7-6H Venturi-Jet, or equivalent
4. Abatement Device Code (See table*) 8 Date of Initial Operation ______
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- Day Hopper **S-** ______ **S-** ______ **S-** ______ **S-** ______
S- ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: 122 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	99.97% for particles < 1 micron. 100% for particles > 1 micron	3
8.	Organics		
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** ______ **A-** ______ **A-** ______ **P-** Day Hopper **P-** ______

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA. . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company

Plant No: A0016

Emission Point No: P-Day Hopp

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S-		**S-**		**S-**		**S-**		**S-**			
S-		**A-**	New	**A-**		**A-**		**A-**		**A-**	

Exit cross-section area: 0.087 sq. ft.

Height above grade: 99.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	486 cfm	486 cfm
Percent Water Vapor	Vol %	Vol %
Temperature	122 °F	122 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored?

Person completing this form Wilma Dreessen

Date 5/1/2021

Form HRA

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

Health Risk Assessment

IMPORTANT: For any permit application that requires a Health Risk Assessment, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Phillips 66 Company Rodeo Facility Plant No.: A0016

Source Description: Day Hopper (typical of 13)

Source No.: S- New/Exempt (if known) Emission Point No.: P- New/Exempt (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ■ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ■ alone OR ☐ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 99.3 feet OR _______ meters?
4. What is the inside diameter of the stack outlet? _______ inches OR 0.333 feet OR _______ meters
5. What is the direction of the exhaust from the stack outlet? ☐ horizontal OR ■ vertical
6. Is the stack outlet: ☐ open or hinged rain flap OR ■ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 486 cfm (cubic feet/min) OR _______ meters^3/second
8. What is the typical temperature of the exhaust gas? 122 degrees Fahrenheit OR _______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

____

____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2						
B3						
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

____

____

____

____

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   ☐ zoned for residential use
   ☐ zoned for mixed residential and commercial/industrial use
   ☒ zoned for commercial and/or industrial use
   ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = ______ feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = ______ feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☐ Industrial/Commercial OR ☐ Other ______________

   ____
5. Distance from source (stack or building) to property line of nearest nonresidential site = ______ feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☒ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   ____

   ____

*K-12 and more than twelve children only

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600, San Francisco, CA 94105 (415) 749-4990 FAX (415) 749-5030
www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: Phillips 66 Plant No: A0016 (if unknown, leave blank)
2. SIC No.: 2869 Date of Initial Operation ______
3. Name or Description: Unit 240 Unicracking Unit Source No.: S- 307
4. Make, Model, and Rated Capacity of Equipment: Custom
5. Process Code[1] 7999 Material Code[2] 509, 351 Usage Unit[2] thou gallons
6. Total throughput, last 12 mos. 870,576 usage units[2] Maximum operating rate: ______ usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: ______ minutes/cycle ______ minutes between cycles
10. Exhaust gases from source: *(at maximum operation)* Wet gas flowrate ______ cfm at ______ °F
Approximate water vapor content ______ volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☐ Check box if factors apply to emissions ***after*** Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	***Basis Code*** [3]
11. Particulate		
12. Organics		
13. Nitrogen Oxides (as NO_2)		
14, Sulfur Dioxide		
15. Carbon Monoxide		
16. Other:		
17. Other:		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** ______ **A-** ______ **A-** ______
P- ______ **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1] **See Tables G-1 through G-7 for code**
[2] **See Table G5 or the Material Codes Table (available upon request)**
[3] **See Basis Code Table below**

Person completing this form: Wilma Dreessen Date: 5/1/2021

DATA FORM T
Organic Liquid Evaporation
(tankage, loading and handling)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. San Francisco, CA 94109. (415) 749-4990 FAX (415)-749-5030

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No: 2869 Date of Initial Operation 1970 Source No S- 97
3. Name or Description Tank 100
4. Code materials* in order of highest throughputs: 1) 509 2) 351 3) ____ 4) ____
5. Total throughput (all materials), last 12 months: ________ thousand gal **or** 15,571 thousand bbl
6. Typical % of total annual throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
   ☐ Check box if loading/handling facility; complete lines 7-11 and omit the remainder of this form. (Also complete one Form T for each storage tank)
7. ● Usage type: ☐ Bulk plant (truck/rail car) ☐ Bulk plant (marine) ☐ Vehicle service station
   ☐ Aircraft/marine servicing Other: ________
8. ● How many nozzles/loading arms? ________ How many pumps? ________
9. ● Make and model of nozzles/loading arms: ________
10. ● Nozzle/arm loads tank by: ☐ splash fill ☐ submerged fill ☐ part splash, part submerged
11. ● Upon loading, vapor space in tank(s) is: ☐ Vented directly to atmosphere
    ☐ Collected by nozzle/arm and sent to Abatement Device(s): A ________ A ________
12. Annual Average: Storage vapor pressure > 11 psia **or** tank temperature ________°F and RVP________psia
13. Highest v.p. of all materials stored: > 11 psia **or** high tank temperature ________°F and high RVP________psia
14. Highest °API of all material stored: ________° Lowest initial B.P. of all materials stored: ______°F
15. Tank Type: ☐ underground ☒ fixed roof ☐ internal floating roof ☐ floating roof
    ☐ pressure ☐ other: ________
16. Tank volume: ______ thousand gallons **or** 303 thousand barrels
17. Tank Diameter: 225 ft height or length: 48 ft Check if applicable: ☐ heated ☒ insulated

Fixed Roof Tanks Only

18. Maximum fill rate: ________gal/hr **or** 20,000 bbl/hr
19. Average height of vapor space: 23.4 ft Highest head space reactivity ______%
    ☒ Check box if emissions from this tank are controlled; complete lines 20 and 21.
20. ● Emissions vent to what source(s) and/or abatement device(s)? S______ S______ A New A______
21. ● Do all gauging/sampling devices have gas-tight covers? ☒ yes ☐ no
22. Paint color: ☐ Aluminum ☒ White ☐ Light grey ☐ Medium grey ☐ Other ________
23. Paint Condition: ☒ good ☐ poor

Floating Roof Tanks Only

24. Shell Type: ☐ gunited ☐ riveted ☐ welded ☐ other: ________
25. Seal Type: ☐ single ☐ double ☐ other: ________ Condition: ☐ tight ☐ loose
26. Maximum withdrawn rate: ________gal/hr **or** ________ bbl/hr
27. Do all gauging/sampling devices enter below liquid level and have gas-tight covers? ☐ yes ☐ no
28. Roof type: ☐ pan ☐ pontoon ☐ other: ________ Is emergency roof drain at least 90% covered? ☐ yes ☐ no

Person completing this form Wilma J Dreessen Date 5/1/2021

See Material Code Reference List.

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description Tank 100 Carbon Adsorption Abatement Device No: A- New
3. Make, Model, and Rated Capacity TBD
4. Abatement Device Code (See table*) 56 Date of Initial Operation ________
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 97 S- ____ S- ____ S- ____ S- ____
S- ____ A- ____ A- ____ A- ____ A- ____ A- ____

6. Typical gas stream temperature at inlet: 80 °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	99.5	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ A- ____ A- ____ A- ____ P- 97 P- ____

Person completing this form: Wilma J. Dressen Date: 05/01/2021

(revised 5/18)

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA. . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Phillips 66 Company Plant No: A0016

Emission Point No: P-97

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 97	**S-**	**S-**	**S-**	**S-**	
S-	**A-** Carbon	**A-**	**A-**	**A-**	**A-**

Exit cross-section area: 0.79 sq. ft.

Height above grade: 10.3 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	1343 cfm	1343 cfm
Percent Water Vapor	0.062 Vol %	0.062 Vol %
Temperature	80 °F	80 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☒ no

What pollutants are monitored?

Person completing this form Wilma Dreessen

Date 5/1/2021

DATA FORM T
Organic Liquid Evaporation
(tankage, loading and handling)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. San Francisco, CA 94109. (415) 749-4990 FAX (415)-749-5030

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No: 2869 Date of Initial Operation 1978 Source No S-334
3. Name or Description Tank 107
4. Code materials* in order of highest throughputs: 1) 351 2) 509 3) ____ 4) ____
5. Total throughput (all materials), last 12 months: ________ thousand gal **or** 10,000 thousand bbl
6. Typical % of total annual throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %

☐ Check box if loading/handling facility; complete lines 7-11 and omit the remainder of this form. (Also complete one Form T for each storage tank)

7. ● Usage type: ☐ Bulk plant (truck/rail car) ☐ Bulk plant (marine) ☐ Vehicle service station ☐ Aircraft/marine servicing Other: ________
8. ● How many nozzles/loading arms? ________ How many pumps? ________
9. ● Make and model of nozzles/loading arms: ________
10. ● Nozzle/arm loads tank by: ☐ splash fill ☐ submerged fill ☐ part splash, part submerged
11. ● Upon loading, vapor space in tank(s) is: ☐ Vented directly to atmosphere ☐ Collected by nozzle/arm and sent to Abatement Device(s): A ________ A ________
12. Annual Average: Storage vapor pressure < 11 psia **or** tank temperature ________°F and RVP________psia
13. Highest v.p. of all materials stored: < 11 psia **or** high tank temperature ________°F and high RVP________psia
14. Highest °API of all material stored: ________° Lowest initial B.P. of all materials stored: ______°F
15. Tank Type: ☐ underground ☐ fixed roof ☒ internal floating roof ☐ floating roof ☐ pressure ☐ other: geodesic dome
16. Tank volume: ______ thousand gallons **or** 200 thousand barrels
17. Tank Diameter: 161 ft height or length: 56 ft Check if applicable: ☐ heated ☐ insulated

Fixed Roof Tanks Only

18. Maximum fill rate: ________gal/hr **or** ________bbl/hr
19. Average height of vapor space: ______ft Highest head space reactivity ______%

☐ Check box if emissions from this tank are controlled; complete lines 20 and 21.

20. ● Emissions vent to what source(s) and/or abatement device(s)? S______ S______ A____ A____
21. ● Do all gauging/sampling devices have gas-tight covers? ☐ yes ☐ no
22. Paint color: ☐ Aluminum ☐ White ☐ Light grey ☐ Medium grey ☐ Other ________
23. Paint Condition: ☐ good ☐ poor

Floating Roof Tanks Only

24. Shell Type: ☐ gunited ☐ riveted ☒ welded ☐ other: ________
25. Seal Type: ☐ single ☒ double ☐ other: ________ Condition: ☒ tight ☐ loose
26. Maximum withdrawn rate: ________gal/hr **or** 920 bbl/hr
27. Do all gauging/sampling devices enter below liquid level and have gas-tight covers? ☒ yes ☐ no
28. Roof type: ☐ pan ☐ pontoon ☒ other: geodesic dome Is emergency roof drain at least 90% covered? ☐ yes ☒ no

Person completing this form Wilma J Dreessen Date 5/1/2021

***See Material Code Reference List.**

DATA FORM T
Organic Liquid Evaporation
(tankage, loading and handling)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. San Francisco, CA 94109. (415) 749-4990 FAX (415)-749-5030

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No: 2869 Date of Initial Operation 1995 Source No S- 440
3. Name or Description Tank 110
4. Code materials* in order of highest throughputs: 1) 551 2) 389 3) ____ 4) ____
5. Total throughput (all materials), last 12 months: ________ thousand gal **or** 6,000 thousand bbl
6. Typical % of total annual throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
   ☐ Check box if loading/handling facility; complete lines 7-11 and omit the remainder of this form. (Also complete one Form T for each storage tank)
7. ● Usage type: ☐ Bulk plant (truck/rail car) ☐ Bulk plant (marine) ☐ Vehicle service station
   ☐ Aircraft/marine servicing Other: ________
8. ● How many nozzles/loading arms? ______ How many pumps? ______
9. ● Make and model of nozzles/loading arms: ________
10. ● Nozzle/arm loads tank by: ☐ splash fill ☐ submerged fill ☐ part splash, part submerged
11. ● Upon loading, vapor space in tank(s) is: ☐ Vented directly to atmosphere
    ☐ Collected by nozzle/arm and sent to Abatement Device(s): A ______ A ______
12. Annual Average: Storage vapor pressure < 11 psia **or** tank temperature ______ °F and RVP ______ psia
13. Highest v.p. of all materials stored: < 11 psia **or** high tank temperature ______ °F and high RVP ______ psia
14. Highest °API of all material stored: ______ ° Lowest initial B.P. of all materials stored: ______ °F
15. Tank Type: ☐ underground ☐ fixed roof ☐ internal floating roof ☒ floating roof
    ☐ pressure ☐ other: ________
16. Tank volume: ______ thousand gallons **or** 161 thousand barrels
17. Tank Diameter: 156 ft height or length: 51 ft Check if applicable: ☐ heated ☐ insulated

Fixed Roof Tanks Only

18. Maximum fill rate: ______ gal/hr **or** ______ bbl/hr
19. Average height of vapor space: ______ ft Highest head space reactivity ______ %
    ☐ Check box if emissions from this tank are controlled; complete lines 20 and 21.
20. ● Emissions vent to what source(s) and/or abatement device(s)? S ____ S ____ A ____ A ____
21. ● Do all gauging/sampling devices have gas-tight covers? ☐ yes ☐ no
22. Paint color: ☐ Aluminum ☐ White ☐ Light grey ☐ Medium grey ☐ Other ________
23. Paint Condition: ☐ good ☐ poor

Floating Roof Tanks Only

24. Shell Type: ☐ gunited ☐ riveted ☒ welded ☐ other: ________
25. Seal Type: ☐ single ☒ double ☐ other: ________ Condition: ☒ tight ☐ loose
26. Maximum withdrawn rate: ______ gal/hr **or** 4300 bbl/hr
27. Do all gauging/sampling devices enter below liquid level and have gas-tight covers? ☒ yes ☐ no
28. Roof type: ☐ pan ☐ pontoon ☒ other: ______ Is emergency roof drain at least 90% covered? ☒ yes ☐ no

Person completing this form Wilma J Dreessen Date 5/1/2021

***See Material Code Reference List.**

DATA FORM T
Organic Liquid Evaporation
(tankage, loading and handling)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. San Francisco, CA 94109. (415) 749-4990 FAX (415)-749-5030

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No: 2869 Date of Initial Operation 1954 Source No S- 108
3. Name or Description Tank 153 (Exempt)
4. Code materials* in order of highest throughputs: 1) 351 2) 509 3) ____ 4) ____
5. Total throughput (all materials), last 12 months: ________ thousand gal **or** ________ thousand bbl
6. Typical % of total annual throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
   ☐ Check box if loading/handling facility; complete lines 7-11 and omit the remainder of this form. (Also complete one Form T for each storage tank)
7. ● Usage type: ☐ Bulk plant (truck/rail car) ☐ Bulk plant (marine) ☐ Vehicle service station ☐ Aircraft/marine servicing Other: ________
8. ● How many nozzles/loading arms? ________ How many pumps? ________
9. ● Make and model of nozzles/loading arms: ________
10. ● Nozzle/arm loads tank by: ☐ splash fill ☐ submerged fill ☐ part splash, part submerged
11. ● Upon loading, vapor space in tank(s) is: ☐ Vented directly to atmosphere
    ☐ Collected by nozzle/arm and sent to Abatement Device(s): A ________ A ________
12. Annual Average: Storage vapor pressure 0.5 psia **or** tank temperature ________°F and RVP________psia
13. Highest v.p. of all materials stored: 0.5 psia **or** high tank temperature ________°F and high RVP________psia
14. Highest °API of all material stored: ________° Lowest initial B.P. of all materials stored: ______°F
15. Tank Type: ☐ underground ☒ fixed roof ☐ internal floating roof ☐ floating roof
    ☐ pressure ☐ other: ________
16. Tank volume: ______ thousand gallons **or** 150 thousand barrels
17. Tank Diameter: 150 ft height or length: 48 ft Check if applicable: ☐ heated ☒ insulated

Fixed Roof Tanks Only

18. Maximum fill rate: ________gal/hr **or** 920 _____bbl/hr
19. Average height of vapor space: 24.8 ft Highest head space reactivity ______%
    ☐ Check box if emissions from this tank are controlled; complete lines 20 and 21.
20. ● Emissions vent to what source(s) and/or abatement device(s)? S______ S______ A____ A____
21. ● Do all gauging/sampling devices have gas-tight covers? ☒ yes ☐ no
22. Paint color: ☐ Aluminum ☒ White ☐ Light grey ☐ Medium grey ☐ Other ________
23. Paint Condition: ☒ good ☐ poor

Floating Roof Tanks Only

24. Shell Type: ☐ gunited ☐ riveted ☐ welded ☐ other: ________
25. Seal Type: ☐ single ☐ double ☐ other: ________ Condition: ☐ tight ☐ loose
26. Maximum withdrawn rate: ________gal/hr **or** ________ bbl/hr
27. Do all gauging/sampling devices enter below liquid level and have gas-tight covers? ☐ yes ☐ no
28. Roof type: ☐ pan ☐ pontoon ☐ other: ________ Is emergency roof drain at least 90% covered? ☐ yes ☐ no

Person completing this form Wilma J Dreessen Date 5/1/2021

See Material Code Reference List.

DATA FORM T
Organic Liquid Evaporation
(tankage, loading and handling)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. San Francisco, CA 94109. (415) 749-4990 FAX (415)-749-5030

1. Business Name: Phillips 66 Company Plant No: A0016 (if unknown, leave blank)
2. SIC No: 2869 Date of Initial Operation 1988 Source No S- 50007
3. Name or Description Tank 224 (Exempt)
4. Code materials* in order of highest throughputs: 1) 351 2) 509 3) ____ 4) ____
5. Total throughput (all materials), last 12 months: ________ thousand gal **or** ________ thousand bbl
6. Typical % of total annual throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %

☐ Check box if loading/handling facility; complete lines 7-11 and omit the remainder of this form. (Also complete one Form T for each storage tank)

7. ● Usage type: ☐ Bulk plant (truck/rail car) ☐ Bulk plant (marine) ☐ Vehicle service station ☐ Aircraft/marine servicing Other: ________
8. ● How many nozzles/loading arms? ________ How many pumps? ________
9. ● Make and model of nozzles/loading arms: ________
10. ● Nozzle/arm loads tank by: ☐ splash fill ☐ submerged fill ☐ part splash, part submerged
11. ● Upon loading, vapor space in tank(s) is: ☐ Vented directly to atmosphere ☐ Collected by nozzle/arm and sent to Abatement Device(s): A ____ A ____
12. Annual Average: Storage vapor pressure 0.5 psia **or** tank temperature ____ °F and RVP ____ psia
13. Highest v.p. of all materials stored: 0.5 psia **or** high tank temperature ____ °F and high RVP ____ psia
14. Highest °API of all material stored: ____ ° Lowest initial B.P. of all materials stored: ____ °F
15. Tank Type: ☐ underground ☒ fixed roof ☐ internal floating roof ☐ floating roof ☐ pressure ☐ other: ________
16. Tank volume: ____ thousand gallons **or** 110 thousand barrels
17. Tank Diameter: 120 ft height or length: 56 ft Check if applicable: ☐ heated ☐ insulated

Fixed Roof Tanks Only

18. Maximum fill rate: ____ gal/hr **or** 4700 bbl/hr
19. Average height of vapor space: 28 ft Highest head space reactivity ____ %

☒ Check box if emissions from this tank are controlled; complete lines 20 and 21.

20. ● Emissions vent to what source(s) and/or abatement device(s)? S ____ S ____ A 7 A ____
21. ● Do all gauging/sampling devices have gas-tight covers? ☒ yes ☐ no
22. Paint color: ☐ Aluminum ☒ White ☐ Light grey ☐ Medium grey ☐ Other ________
23. Paint Condition: ☒ good ☐ poor

Floating Roof Tanks Only

24. Shell Type: ☐ gunited ☐ riveted ☐ welded ☐ other: ________
25. Seal Type: ☐ single ☐ double ☐ other: ________ Condition: ☐ tight ☐ loose
26. Maximum withdrawn rate: ________ gal/hr **or** ________ bbl/hr
27. Do all gauging/sampling devices enter below liquid level and have gas-tight covers? ☐ yes ☐ no
28. Roof type: ☐ pan ☐ pontoon ☐ other: ________ Is emergency roof drain at least 90% covered? ☐ yes ☐ no

Person completing this form Wilma J Dreessen Date 5/1/2021

See Material Code Reference List.

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

375 Beale Street, Suite 600. . . San Francisco, CA 94105. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Phillips 66 Company Plant No: A0016 (If unknown, leave blank)
2. Name or Description Vapor Recovery Abatement Device No: A- 7
3. Make, Model, and Rated Capacity Custom
4. Abatement Device Code (See table*) 64 fuel gas Date of Initial Operation ______
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 50007 S- ______ S- ______ S- ______ S- ______
S- ______ A- ______ A- ______ A- ______ A- ______ A- ______

6. Typical gas stream temperature at inlet: ambient °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate		
8.	Organics	100	4
9.	Nitrogen Oxides (as NO_2)		
10.	Sulfur Dioxide		
11.	Carbon Monoxide		
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- 50007 A- ______ A- ______ A- ______ P- ______ P- ______

Person completing this form: Wilma J. Dreessen Date: 05/01/2021

(revised 5/18)

Permit Services Division
Bay Area Air Quality Management District
939 Ellis Street, San Francisco, CA 94109 • 749-4990

Stationary Source Summary
Page 1

FACILITY NAME: Phillips 66 Rodeo Facility | **FACILITY ID: A0016**

♦ DISTRICT USE ONLY ♦

Application #: ____________________ **Application Received:** ____________________

Application Filing Fee: ____________________ **Application Deemed Complete:** ____________________

I. FACILITY IDENTIFICATION

1. Facility Name: Phillips 66 Rodeo Facility
2. Four digit SIC Code: 2869 EPA Plant ID: ____________________
3. Parent Company (if different than Facility Name): Phillips 66 Company
4. Mailing Address: 1380 San Pablo Avenue, Rodeo, CA 94572
5. Street Address or Source Location: 1380 San Pablo Avenue, Rodeo, CA 94572
6. UTM Coordinates (if required): ____________________
7. Source Located within 50 miles of the state line: ☐ Yes X No
8. Source Located within 1000 feet of a school: ☐ Yes X No
9. Type of Organization X Corporation ☐ Sole Ownership ☐ Government ☐ Partnership ☐ Utility Company
10. Legal Owner's Name: Phillips 66 Company
11. Owner's Agent name (if any): ____________________
12. Responsible Official: Richard G. Harbison
13. Plant Site Manager/**Contact**: Wilma Dreessen Telephone #: (510) 245-5893
14. Type of Facility: Renewable Fuels Manufacturing and Gasoline Blending Facility
15. General description of processes/products: Manufacturing of renewable fuels from renewable feedstocks, including renewable diesel, renewable naphtha, renewable jet fuel. Blending of gasoline blendstocks.
16. Is a Federal Risk Management Plan pursuant to Section 112(r) required? Yes X No
(If application is submitted after Risk Management Plan due date, attach verification that the plan is registered with the appropriate agency.)

Permit Services Division
Bay Area Air Quality Management District
939 Ellis Street, San Francisco, CA 94109 • 749-4990

Stationary Source Summary
Page 2

FACILITY NAME: Phillips 66 Rodeo Facility

FACILITY ID:A0016

II. TYPE OF PERMIT ACTION

	CURRENT PERMIT (permit number)	EXPIRATION (date)
☐ Initial Title V Application		
☐ Permit Renewal		
☐ Significant Permit Modification		
☒ Minor Permit Modification	A0016	1/24/2023
☐ Administrative Amendment		

III. DESCRIPTION OF PERMIT ACTION

1. Does the permit action requested involve:

☐ Temporary Source
☐ Acid Rain Source
☐ CEM's
☐ Source Subject to MACT Requirements [Section 112]
☐ Source Subject to Enhanced Monitoring
☐ Voluntary Emissions Caps
☐ Alternative Operating Scenarios
X Abatement Devices

2. Is source operating under a Compliance Schedule? ☐ Yes X No

3. For permit modification, provide a general description of the proposed permit modification:

Minor revision of Title V permit to change the facility from a petroleum crude oil processing facility to a renewable fuels manufacturer.

Signature of Responsible Official

Richard G. Harbison
Name of Responsible Official

Date: 5/20/2021

APPENDIX B
EMISSIONS DOCUMENTATION

Stationary Source Table 1
Unit 237 Sulfur Treatment Unit Emissions
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Operational Parameters[1]

Parameter	Value	Units
# Thermal Oxidizers	2	--
Natural Gas Firing Rate (per ThermOx)	7.4	MMBtu/hr
Natural Gas Firing Rate (Total)	14.8	MMBtu/hr
Natural Gas HHV	1,050	Btu/Scf
Natural Gas Flow	14,095	scf/hr
Hours per Day	24	hr/day
Days per Year	365	day/yr

Emissions Calculations

Pollutant	Emission Factor		Emissions	
	Value	Units	lb/day	ton/yr (MT/yr for CO_2)
CAPs[2]				
POC	5.5	lb/MMscf	1.9	0.34
NOx	24.8	ton/yr	136	25
CO	84.0	lb/MMscf	28	5.2
SO_2	2.00	lb/hr	48	8.8
PM_{10} (as sulfuric acid mist)	6.4	ton/yr	35	6.4
$PM_{2.5}$ (as sulfuric acid mist)	6.4	ton/yr	35	6.4
TACs[3]				
Benzene	2.1E-06	lb/Mscf	7.1E-04	1.3E-04
Formaldehyde	7.5E-05	lb/Mscf	0.025	0.0046
Toluene	3.4E-06	lb/Mscf	0.0012	2.1E-04
Sulfuric Acid	6.4	ton/yr	35	6.4
GHGs[2]				
CO_2e (NG combustion)	120,000	lb/MMscf	40,594	6,721
CO_2e (acid gas content)	5,150	lb/hr	123,600	20,463
Total CO_2e	--	--	164,194	27,184

Notes:

[1] Natural gas feed rate to each thermal oxidizer based on engineering design.

[2] NOx, SO_2, and PM emission rates based on engineering design. POC, CO, and CO_2 emissions assumed to be from combustion, with emission factors from AP-42 Chapter 1, Section 4 "Natural Gas Combustion" Tables 1.4-1 and 1.4-2. Additional CO_2 emissions are expected due to the composition of the acid gas stream. This CO_2 emission factor is based on engineering design. The acid gas related CO_2 emissions shown above represent total Post-Project CO_2 emissions from this stream.

[3] Benzene, formaldehyde, and toluene emissions are assumed to be from natural gas combustion. Emission factors are from BAAQMD policy guidance, referencing AP-42 Chapter 1, Section 4, "Natural Gas Combustion" Table 1.4-3 and are based on 1,020 BTU/scf. Particulate matter emissions are reported as sulfuric acid mist and thus these emissions are accounted for in both the CAP and TAC sections.

Abbreviations:

CAP - Criteria Air Pollutant
CO - carbon monoxide
CO_2 - carbon dioxide
GHG - Greenhouse Gas
HHV - higher heating value
hr - hour
lb - pound
lbmol - pound-mole
MMBtu - million British thermal units
MT - metric ton
NOx - nitrogen oxides
POC - Precursor Organic Compounds
PM_{10} - particulate matter less than 10 microns in diameter
scf - standard cubic feet
SO_2 - sulfur dioxide
TAC - toxic air contaminant
VOC - volatile organic compounds
yr - year

References:

US EPA. AP 42, Fifth Edition, Volume 1, Chapter 1 Section 4 "Natural Gas Combustion". Available at: https://www3.epa.gov/ttn/chief/ap42/ch01/

Stationary Source Table 2
Potential Equipment Component Emissions from Pretreatment Unit
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Process Component Counts[1]

Fugitive Component Type	PTU Train 1		PTU Train 2		PTU Train 3		FOG Recovery and DAF		Total Number of Components
	Oil	**Waste Water**	**Oil**	**Waste Water**	**Oil**	**Waste Water**	**Oil**	**Waste Water**	
Connectors	5,975	308	3,909	308	5,975	308	--	1,540	18,323
Valves	1,494	77	977	77	1,494	77	--	385	4,581
Pressure Relief Valves	46	--	48	--	46	--	-	14	153
Process Drains	--	--	--	--	--	--	--	--	--
Pumps/All Others	161	41	111	41	161	41	-	39	593

POC Emission Factors[2]

Component Type	Equation	Leak Rate (ppm)	Emission Factor (kg/hr/comp)
Valves	2.27E-06(SV)^0.747	10	1.27E-05
Pumps	5.07E-05(SV)^0.622	10	2.12E-04
Others	8.69E-06(SV)^0.642	10	3.81E-05
Connectors	1.53E-06(SV)^0.736	10	8.33E-06
Pressure Relief Device	8.69E-06(SV)^0.642	10	3.81E-05

Emissions Calculations[3]

Fugitive Component Type	Total Number of Components	POC Emissions	
		lb/day	**ton/year**
Connectors	18,323	8.1	1.5
Valves	4,581	3.1	0.56
Pressure Relief Valves	153	0.31	0.056
Process Drains	--	--	--
Pumps/All Others	593	6.7	1.2
	Total	18	3.3

Notes:

1. Process component counts based on engineering design.
2. Emission factors were calculated using equations from CAPCOA "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities" Table IV-3a. Leak rates were based on engineering design.
3. Emissions calculated assuming continuous facility operation (24 hours/day, 365 days/year).

Abbreviations:

hr - hour	POC - precursor organic compound
kg - kilogram	ppm - parts per million
lb - pound	PTU - Pretreatment Unit

References:

CAPCOA. California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. February 1999. Available online: https://ww3.arb.ca.gov/fugitive/impl_doc.pdf

Stationary Source Table 3
Wet Surface Air Cooler Emissions
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Throughput[1]

Value	Units
8,000	gpm
6	Circulations
12	MMgal/day
4,205	MMgal/yr

PM Emission Factor Derivation

Source	Percent Drift[2]	TDS[3]	PM EF[4]
	vol%	mg/L	lb/MMgal
WSAC	0.0005%	190	0.0079

PM Emissions

Source	PM_{10} Emissions[4]		$PM_{2.5}$ Emissions[4]	
	(lb/day)	(ton/year)	(lb/day)	(ton/year)
WSAC	0.55	0.10	0.55	0.10

Notes:

[1] Throughput in gallons per minute based on engineering design. Daily and annual throughput calculated assuming continuous operation.

[2] Percent drift based on engineering design. Drift eliminators will be installed.

[3] Total dissolved solids (TDS) concentration estimated to be 140-190 mg/L by East Bay Municipal Water District. Maximum of range selected for most conservative emissions estimate.

[4] Consistent with AP-42 Chapter 13 Section 4 methodology, all TDS conservatively assumed to be PM_{10}. For the purposes of estimating post-project emissions from new sources, PM_{10} also conservatively set equal to $PM_{2.5}$ emissions.

Abbreviations:

EF - emission factor
gpm - gallons per minute
L - liters
lb - pound
mg - milligrams
MMgal - million gallons
PM_{10} - particulate matter less than 10 microns in diameter
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter
TDS - total dissolved solids
yr - year

References:

US EPA. AP-42, Fifth Edition, Volume 1, Chapter 13 Section 4 "Wet Cooling Towers". Available online: https://www3.epa.gov/ttnchie1/ap42/ch13/final/c13s04.pdf

Stationary Source Table 4
Vapor Recovery System Emissions
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Train	Vapor Flow Rate[1]	VOC Concentration[1]	VOC Uncontrolled[1]	Control Efficiency[1]	VOC Emission Rate[2]	
	lb/hr	ppmw	lb/hr	%	lb/day	ton/yr
PTU Train 1	3,307	388	1.3	99.5%	0.15	0.028
PTU Train 2	2,142		0.83		0.10	0.018
PTU Train 3	3,307		1.3		0.15	0.028
FOG Recovery and DAF	3,307		1.3		0.15	0.028
Total:			4.7		0.56	0.10

Notes:

[1] All parameters are based on engineering design.

[2] Daily and annual VOC emission rates calculated using hourly uncontrolled emission rate and control efficiency, assuming continuous facility operation.

Abbreviations:

FOG - Fats, oils, and greases
hr - hour
lb - pound
PTU - Pretreatment Unit
yr - year

Stationary Source Table 5
Material Handling Emissions
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Material Handling Emissions from Pretreatment Unit Silos and Day Hoppers[1]

Train	Material	Solids Throughput	Particle Size < 1 microns[2]	Control Efficiency[3]	Number of Tranfer Points[4]	Criteria Air Pollutant Emissions			Toxic Air Contaminant Emissions			
						$PM_{10}/PM_{2.5}$ Emission Rate[5,6]			Crystalline Silica Content[7]	Crystalline Silica Emission Rate[5,8]		
		lb/hr	%	%		lb/hour	lb/day	ton/yr	wt% of PM	lb/hour	lb/day	ton/yr
PTU Train 1	Bleached Earth	4,110	3.0%	99.97%	2	0.074	1.8	0.32	5%	0.0037	0.089	0.016
	Filter Aid	3,154				0.057	1.4	0.25	50%	0.028	0.68	0.12
PTU Train 2	Bleached Earth	4,110				0.074	1.8	0.32	5%	0.0037	0.089	0.016
	Filter Aid	276				0.0050	0.12	0.022	50%	0.0025	0.060	0.011
PTU Train 3	Bleached Earth	4,110				0.074	1.8	0.32	5%	0.0037	0.089	0.016
	Filter Aid	3,154				0.057	1.4	0.25	50%	0.028	0.68	0.12
Total Emissions						**0.34**	**8.2**	**1.5**	--	**0.070**	**1.7**	**0.31**

Criteria Air Pollutant Emissions per Piece of Equipment[6]

Train	Material	First Transfer Point			Second Transfer Point		
		Silos	$PM_{10}/PM_{2.5}$ Emission Rate Per Silo		Day Hopper	$PM_{10}/PM_{2.5}$ Emission Rate Per Day Hopper	
		Number	lb/day	ton/yr	Number	lb/day	ton/yr
PTU Train 1	Bleached Earth	4	0.22	0.041	2	0.44	0.081
	Filter Aid	4	0.17	0.031	3	0.23	0.041
PTU Train 2	Bleached Earth	4	0.22	0.041	2	0.44	0.081
	Filter Aid	1	0.060	0.011	1	0.060	0.011
PTU Train 3	Bleached Earth	4	0.22	0.041	2	0.44	0.081
	Filter Aid	4	0.17	0.031	3	0.23	0.041

Toxic Air Contaminant Emissions per Piece of Equipment[6]

Train	Material	First Transfer Point			Second Transfer Point		
		Silos	Crystalline Silica Emission Rate Per Silo		Day Hopper	Crystalline Silica Emission Rate Per Day Hopper	
		Number	lb/day	ton/yr	Number	lb/day	ton/yr
PTU Train 1	Bleached Earth	4	0.011	0.0020	2	0.022	0.0041
	Filter Aid	4	0.085	0.016	3	0.11	0.021
PTU Train 2	Bleached Earth	4	0.011	0.0020	2	0.022	0.0041
	Filter Aid	1	0.030	0.0054	1	0.030	0.0054
PTU Train 3	Bleached Earth	4	0.011	0.0020	2	0.022	0.0041
	Filter Aid	4	0.085	0.016	3	0.11	0.021

Notes:

[1] Material handling dust emissions will be generated during transfer of bleached earth and filter aid from trucks to silos and from silos to day hoppers. Hourly throughput rates and stream composition based on engineering design and represent material moving per transfer.

[2] Particle size information based on engineering design provided by equipment vendor.

[3] Dust filter control specifications and maximum air flowrate based on engineering design. Control Efficiency is 99.97% for particles < 1 micron. Control efficiency is 100% for particles > 1 micron.

[4] Each source has two transfer points. Material is assumed to be transferred at an equal rate from the trucks to the silos and from the silos to the day hoppers.

[5] Particulate matter emissions are less than 1 micron, therefore PM_{10} and $PM_{2.5}$ emission rates are equal.

[6] Daily and annual emission rates calculated assuming continuous operation of the pretreatment unit (24 hours per day, 365 days per year).

[7] Crystalline silica content from manufacturer's SDS. For each material, the upper end of the weight percent range was conservatively selected.

[8] Crystalline silica emissions calculated by multiplying the PM emission rate for each material and train by the crystalline silica content.

Abbreviations:

ft^3 - cubic feet
hr - hour
lb - pound
m^3 - cubic meters
mg - milligrams
PM_{10} - particulate matter less than 10 microns in diameter
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter
PTU - Pretreatment Unit
yr - year

Stationary Source Table 6
R12-15 Baseline Emissions Inventory for Existing Project Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Description	Source Category	Project Status	CAPs (tons/year)[1]																		GHGs (MT)[1]		
				NOX			SO_2			CO			POC			PM_{10}			$PM_{2.5}$					
				2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
97	Tank 100	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	1.3	1.3	1.5	--	--	--	--	--	--	2.7	2.7	3.4
307	U240 Unicracking Unit	Equipment Leaks	Altered	--	--	--	--	--	--	--	--	--	4.7	4.4	4.1	--	--	--	--	--	--	NA	NA	--
334	Tank 107	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	0.92	0.88	0.81	--	--	--	--	--	--	2.0	2.0	2.5
440	Tank 110	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	0.28	0.75	0.69	--	--	--	--	--	--	0.76	0.75	1.0
50007	Tank 224	Fixed Roof Tank	Existing - Exempt	--	--	--	--	--	--	--	--	--	1.8	3.1	3.8	--	--	--	--	--	--	2.7	2.7	3.4
109	Tank 154	External Floating Roof Tank	Contemporaneous	--	--	--	--	--	--	--	--	--	0.12	0.14	0.12	--	--	--	--	--	--	0.19	0.19	0.24
439	Tank 109	External Floating Roof Tank	Contemporaneous	--	--	--	--	--	--	--	--	--	0.46	0.81	0.94	--	--	--	--	--	--	1.1	1.1	1.4
442	Tank 112	External Floating Roof Tank	Contemporaneous	--	--	--	--	--	--	--	--	--	0.79	0.75	0.72	--	--	--	--	--	--	1.7	1.7	2.2
29	Unit 200 B-5 Heater	Stationary Combustion	Shutdown	11	10	12	19	16	19	0.35	0.42	0.38	1.7	1.4	1.7	2.3	1.9	2.3	2.3	1.9	2.3	44,846	35,133	41,419
30	Unit 200 B-101 Heater	Stationary Combustion	Shutdown	5.5	4.1	8.6	7.4	7.0	8.1	0.19	0.26	0.18	0.65	0.61	0.71	0.89	0.84	1.0	0.89	0.84	1.0	17,453	15,758	17,696
36	Unit 200 B-102 Heater	Stationary Combustion	Shutdown	1.5	1.4	1.6	1.3	1.7	1.5	0.47	0.61	0.66	0.88	0.81	0.93	1.2	1.1	1.3	1.2	1.1	1.3	26,497	24,156	27,330
301	Molten Sulfur Pit 234	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
302	Molten Sulfur Pit 236	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
303	Molten Sulfur Pit 238	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
350	Unit 267 Crude Distillation Unit	Equipment Leaks	Shutdown	--	--	--	--	--	--	--	--	--	3.0	3.6	3.5	--	--	--	--	--	--	NA	NA	--
351	Unit 267 B-601/602 Tower Preheaters	Stationary Combustion	Shutdown	5.1	3.6	3.7	17	18	16	0.37	6.7	0.59	1.5	1.5	1.5	2.0	2.0	2.0	2.0	2.0	2.0	40,018	37,932	36,692
1002	Unit 236 Sulfur Plant	Sulfur Recovery Unit	Shutdown	1.7	1.5	1.6	3.5	4.9	4.9	12	11	12	0.029	0.033	0.038	0.26	0.94	2.0	0.26	0.94	2.0	5,552	6,334	6,104
		Equipment Leaks		--	--	--	--	--	--	--	--	--	0.48	0.47	0.35	--	--	--	--	--	--	NA	NA	--
1003	Unit 238 Sulfur Plant	Sulfur Recovery Unit	Shutdown	3.7	4.5	3.8	5.6	7.9	3.0	34	41	34	0.029	0.033	0.038	0.46	1.6	1.2	0.46	1.6	1.2	8,577	10,341	9,260
		Equipment Leaks		--	--	--	--	--	--	--	--	--	0.057	0.33	0.12	--	--	--	--	--	--	NA	NA	--
Plant ID 21360	Carbon Plant	Carbon Plant	Shutdown	325	407	359	1,324	1,644	1,080	10	13	11	0.20	0.20	0.30	21	27	21	20	25	19	145,794	190,631	169,424

Source Number	Description	Source Category	Project Status	TACs (tons/year)[1]																	
				Lead and Compounds			Sulfuric Acid			Fluorides			Hydrogen Sulfide			Beryllium and Compounds			Mercury and Compounds		
				2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
97	Tank 100	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	0.016	0.017	0.018	--	--	--	8.1E-11	1.3E-10	2.3E-10
307	U240 Unicracking Unit	Equipment Leaks	Altered	--	--	--	--	--	--	--	--	--	0.024	0.021	0.019	--	--	--	--	--	--
334	Tank 107	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	0.011	0.011	0.010	--	--	--	--	1.8E-10	1.7E-10
440	Tank 110	External Floating Roof Tank	Altered	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
50007	Tank 224	Fixed Roof Tank	Existing - Exempt	--	--	--	--	--	--	--	--	--	0.016	0.028	0.034	--	--	--	--	--	--
109	Tank 154	External Floating Roof Tank	Demolished	--	--	--	--	--	--	--	--	--	1.7E-04	1.6E-04	1.6E-04	--	--	--	--	--	--
439	Tank 109	External Floating Roof Tank	Demolished	--	--	--	--	--	--	--	--	--	0.0057	0.0089	0.011	--	--	--	2.3E-10	5.4E-10	3.1E-10
442	Tank 112	External Floating Roof Tank	Demolished	--	--	--	--	--	--	--	--	--	0.010	0.010	0.0094	--	--	--	3.6E-11	5.9E-10	9.0E-10
29	Unit 200 B-5 Heater	Stationary Combustion	Shutdown	7.4E-04	6.0E-04	7.4E-04	1.0	1.2	1.4	--	--	--	0.024	0.020	0.024	4.4E-06	3.6E-06	4.4E-06	7.2E-05	5.9E-05	7.2E-05
30	Unit 200 B-101 Heater	Stationary Combustion	Shutdown	2.9E-04	2.7E-04	3.2E-04	0.38	0.52	0.60	--	--	--	0.0094	0.0088	0.010	1.7E-06	1.6E-06	1.9E-06	2.8E-05	2.6E-05	3.1E-05
36	Unit 200 B-102 Heater	Stationary Combustion	Shutdown	3.0E-04	2.7E-04	2.7E-04	0.067	0.12	0.11	--	--	--	0.010	0.0088	0.0088	1.8E-06	1.6E-06	1.6E-06	2.9E-05	2.6E-05	2.6E-05
301	Molten Sulfur Pit 234	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
302	Molten Sulfur Pit 236	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
303	Molten Sulfur Pit 238	Sulfur Recovery Unit	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
350	Unit 267 Crude Distillation Unit	Equipment Leaks	Shutdown	--	--	--	--	--	--	--	--	--	0.0015	0.0019	0.0019	--	--	--	2.7E-10	3.8E-10	--
351	Unit 267 B-601/602 Tower Preheaters	Stationary Combustion	Shutdown	6.5E-04	6.5E-04	6.5E-04	0.86	1.3	1.2	--	--	--	0.021	0.021	0.021	3.8E-06	3.8E-06	3.8E-06	6.3E-05	6.4E-05	6.3E-05
1002	Unit 236 Sulfur Plant	Sulfur Recovery Unit	Shutdown	3.9E-05	4.5E-05	5.2E-05	0.13	0.14	0.77	--	--	--	0.040	0.055	0.055	2.3E-07	2.7E-07	3.1E-07	3.8E-06	4.4E-06	5.1E-06
		Equipment Leaks		--	--	--	--	--	--	--	--	--	0.0020	0.0017	1.3E-04	--	--	--	--	--	--
1003	Unit 238 Sulfur Plant	Sulfur Recovery Unit	Shutdown	3.9E-05	4.5E-05	5.2E-05	0.58	0.38	0.83	--	--	--	0.062	0.088	0.034	2.3E-07	2.7E-07	3.1E-07	3.8E-06	4.4E-06	5.1E-06
		Equipment Leaks		--	--	--	--	--	--	--	--	--	1.5E-04	4.5E-04	2.6E-09	--	--	--	--	--	--
Plant ID 21360	Carbon Plant	Carbon Plant	Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Notes:

[1] Baseline emissions for all sources other than the Carbon Plant obtained from Phillips 66's 2017, 2018, and 2019 R12-15 emissions inventories. Carbon Plant emissions are from BAAQMD Permit to Operate invoices.

Abbreviations:

CAPs - Criteria Air Pollutant
CO - carbon monoxide
CO_2e - carbon dioxide equivalents
GHGs - Greenhouse Gases
MT - metric ton
NOx - nitrogen oxides
PM_{10} - particulate matter less than 10 microns in diameter
$PM_{2.5}$ - particulate matter less than 2.5 microns in diameter
POC - precursor organic compounds
SO_2 - sulfur dioxide
TACs - toxic air contaminants
yr - year

Stationary Source Table 7
Post-Project Potential Change in Equipment Component POC Emissions from Existing Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Process Component Counts[1]

Location	Fugitive Component Type	Renewable Feedstocks	Renewable Diesel	Renewable Naphtha	Renewable Jet	Propane	RFG
		HL	**HL**	**LL**	**HL**	**LL**	**GV**
Unit 240	Connectors	123	151	616	263	73	106
	Valves	31	38	154	66	18	27
	Pressure Relief Valves	1.3	--	1.3	--	--	--
	Process Drains	--	--	--	--	--	--
	Pumps/All Others	2.2	--	2.2	--	--	--

POC Emission Factors[2]

Component Type	Equation	HL Leak Rate (ppm)	LL/GV Leak Rate (ppm)	HL Emission Factor (kg/hr/comp)	LL/GV Emission Factor (kg/hr/comp)
Valves	2.27E-06(SV)^0.747	10	100	1.27E-05	7.08E-05
Pumps	5.07E-05(SV)^0.622	10	500	2.12E-04	2.42E-03
Others	8.69E-06(SV)^0.642	10	100	3.81E-05	1.67E-04
Connectors	1.53E-06(SV)^0.736	10	100	8.33E-06	4.54E-05
Pressure Relief Device	8.69E-06(SV)^0.642	10	500	3.81E-05	4.70E-04

Emissions[3]

Location	Fugitive Component Type	Renewable Feedstocks	Renewable Diesel	Renewable Naphtha	Renewable Jet	Propane	RFG
		(VOC lb/day)					
Unit 240	Connectors	0.054	0.067	1.5	0.12	0.17	0.26
	Valves	0.021	0.025	0.58	0.044	0.068	0.10
	Pressure Relief Valves	0.0026	--	0.032	--	--	--
	Process Drains	--	--	--	--	--	--
	Pumps/All Others	0.025	--	0.28	--	--	--
	Unit 240 Total (lb/day)	**0.10**	**0.092**	**2.4**	**0.16**	**0.24**	**0.36**

Notes:

[1] Counts are based on engineering design.

[2] Emission factors were calculated using equations from CAPCOA "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities" Table IV-3a. Leak rates for all components in heavy liquid service assumed to be 10ppm. Leak rates for components in light liquid service vary by component type and are from 2019 R12-15 calculations for the facility. Consistent with CAPCOA guidance, drains are assumed to fall into the "Other" component category.

[3] Emissions calculated assuming continuous facility operation (24 hours/day, 365 days/year).

Abbreviations:

GV - Gas/Vapor
HL - Heavy Liquid
hr - hour
kg - kilogram
lb - pound
LL - Light Liquid
POC - precursor organic compound
ppm - parts per million

References:

CAPCOA. California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. February 1999. Available online: https://ww3.arb.ca.gov/fugitive/impl_doc.pdf

Stationary Source Table 8
Post-Project Potential Change in Equipment Component TAC Emissions from Existing Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Annual Change in VOC Emissions by Unit and Material Service[1]

Location	Renewable Feedstocks	Renewable Diesel	Renewable Naphtha	Renewable Jet	Propane	RFG
	(VOC ton/yr)					
Unit 240	0.019	0.017	0.43	0.029	0.044	0.065

TAC Content by Material Service[2]

Chemical Name[1,2]	CAS No.	Renewable Feedstocks	Renewable Diesel	Renewable Naphtha	Renewable Jet	Propane	RFG
		wt %					
Hydrogen sulfide	7783-06-4	--	--	--	--	0.38	1.0E-04

TAC Emissions by Unit

Chemical Name[1,2]	CAS No.	Unit 240 (ton/yr)
Hydrogen sulfide	7783-06-4	1.7E-04

Notes:

[1] Emissions calculated in Stationary Source Table 7.

[2] Speciations obtained from facility's R12-15 Emissions Inventory or based on engineering design.

Abbreviations:

lb - pound
TAC - Toxic Air Contaminant
yr- year

Stationary Source Table 9
Summary of Baseline and Post-Project Tank Service
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Tank Number[1]	Baseline PTE			Post-Project Actual			Post-Project PTE		
		Stock	Annual Average Bulk Temperature (°F)	Throughput (bbl/yr)	Stock	Annual Average Bulk Temperature (°F)	Throughput (bbl/yr)	Stock	Annual Average Bulk Temperature (°F)	Throughput (bbl/yr)
97	Tank 100	Crude-Blended	Ambient	15,571,000	Renewable Feedstock	130	12,600,000	Renewable Feedstock	130	15,571,000
334	Tank 107	Crude-Blended	Ambient	10,000,000	Renewable Feedstock	130	7,300,000	Gasoline TVP 10.99	Ambient	10,000,000
440	Tank 110	Gasoline TVP 10.99	Ambient	3,600,000	Gasoline	Ambient	6,000,000	Gasoline TVP 10.92	Ambient	6,000,000
108	Tank 153	--	--	--	Renewable Feedstock	130	7,300,000	--	--	--
50007	Tank 224	--	--	--	Renewable Feedstock	Ambient	3,500,000	--	--	--

Notes:

[1] Baseline PTE, Post-Project Actual Emissions, and Post-Project PTE was evaluated for altered tanks. Note that Tank 100, Tank 107, and Tank 110 are altered, while Tank 153 and Tank 224 are exempt. Stock parameters, bulk temperature, and throughput rates are based on permit conditions and engineering design.

Abbreviations:

bbl - barrel(s)
°F - degrees Fahrenheit
yr - year

Stationary Source Table 10
Summary of Baseline and Post-Project Tank Parameters
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Tank Number	Scenario	General Tank Parameters										
			Diameter ft	Height ft	Roof Type	Fixed Roof Type	Shell Color	Shell Condition	Roof color	Roof Condition	Vapor Control Efficiency %	Shell Insulated?	Roof Insulated?
97	**Tank 100**	Baseline	225	48	**EFRT (pontoon-type)**	**None (open top)**	White	Average	White	Average	**0**	**TRUE**	**TRUE**
334	**Tank 107**		161	56	**EFRT (double-deck)**	**None (open top)**	White	**Average**	White	Average	0	**FALSE**	**FALSE**
440	Tank 110		156	51	EFRT (double-deck)	None (open top)	White	Average	White	Average	0	FALSE	FALSE

Source Number	Tank Number	Scenario	General Tank Parameters										
			Diameter ft	Height ft	Roof Type	Fixed Roof Type	Shell Color	Shell Condition	Roof color	Roof Condition	Vapor Control Efficiency %	Shell Insulated?	Roof Insulated?
97	**Tank 100**	Post-Project	225	48	**Fixed Roof**	**Cone (column-supported)**	White	Average	White	Average	**100**	**TRUE**	**TRUE**
334	**Tank 107**		161	56	**IFRT (welded deck)**	**Dome (self-supported)**	White	**New**	White	Average	0	**TRUE**	**FALSE**
440	Tank 110		156	51	EFRT (double-deck)	Cone (column-supported)	White	Average	White	Average	0	FALSE	FALSE
108	**Tank 153**	Post-Project - Exempt	150	48	**Fixed Roof**	**Cone (column-supported)**	White	Average	White	Average	0	**TRUE**	**TRUE**
50007	**Tank 224**		120	56	Fixed Roof	Cone (column-supported)	White	Average	White	Average	**100**	FALSE	FALSE

Notes:

1. Tank parameters for baseline and post-project scenarios based on engineering design. Bold font indicates a parameter that changed between the baseline and post-project scenarios.
2. Emissions calculations conducted using AP-42 Chapter 7 methodology. Any tank parameter required in the calculation but not shown above (such as operating pressure, tank condition, etc.) is assumed to be default. Note that parameters specific to floating roof tanks are shown in Stationary Source Table 11.

Stationary Source Table 11
Summary of Baseline and Post-Project Floating Roof Parameters
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Tank Number	Scenario	Roof Type	Floating Roof Tank Parameters											
				Rim Seal Fitting	Rim Seal Type	Guide Pole		Access Hatch		Gauge Float		Gauge Hatch		Vacuum Breaker	
						Type	Quantity	Type	Quantity	Type	Quantity	Type	Quantity	Type	Quantity
97	**Tank 100**	Baseline	**EFRT (pontoon-type)**	Tight	Mechanical-shoe seal, rim-mounted secondary	Unslotted, gasketed sliding cover w/pole wiper	1	Bolted cover, gasketed	2	Unbolted cover, gasketed	1	Weighted mechanical actuation, gasketed	1	Weighted mechanical actuation, gasketed	2
334	**Tank 107**		**EFRT (double-deck)**	Tight	Mechanical-shoe seal, rim-mounted secondary	Unslotted, gasketed sliding cover w/pole wiper	1	Bolted cover, gasketed	2	Unbolted cover, gasketed	1	Weighted mechanical actuation, gasketed	1	Weighted mechanical actuation, gasketed	2
440	Tank 110		EFRT (double-deck)	Tight	Mechanical-shoe seal, rim-mounted secondary	Unslotted, gasketed sliding cover w/pole wiper	1	Bolted cover, gasketed	1	Bolted cover, gasketed	1	Weighted mechanical actuation, gasketed	1	Weighted mechanical actuation, gasketed	2
97	**Tank 100**	Post-Project	**Fixed Roof**												
334	**Tank 107**		**IFRT (welded deck)**	Tight	Mechanical-shoe seal, rim-mounted secondary	Unslotted, gasketed sliding cover w/pole wiper	1	Bolted cover, gasketed	2	Unbolted cover, gasketed	1	Weighted mechanical actuation, gasketed	1	Weighted mechanical actuation, gasketed	2
440	Tank 110		EFRT (double-deck)	Tight	Mechanical-shoe seal, rim-mounted secondary	Unslotted, gasketed sliding cover w/pole wiper	1	Bolted cover, gasketed	1	Bolted cover, gasketed	1	Weighted mechanical actuation, gasketed	1	Weighted mechanical actuation, gasketed	2
108	**Tank 153**	Post-Project - Exempt	**Fixed Roof**												
50007	Tank 224		**Fixed Roof**												

Source Number	Tank Number	Scenario	Floating Roof Tank Parameters (cont.)															
			Deck Drain		Leg Pontoon Area		Leg Center Area		Rim Vent		Column		Ladder		Effective ft	Panel ft	Panel ft
			Type	Quantity	Type	Quantity	Type	Quantity	Type	Quantity	Type	Quantity	Type	Quantity			
97	**Tank 100**	Baseline	90% closed	0	Adjustable - sock	23	Adjustable - sock	140	N/A	0	N/A	0	N/A	0	AP-42 Default		
334	**Tank 107**		90% closed	2	N/A	0	Adjustable - sock	58	N/A	0	N/A	0	N/A	0	AP-42 Default		
440	Tank 110		90% closed	1	N/A	0	Adjustable - sock	58	N/A	0	N/A	0	N/A	0	AP-42 Default		
97	**Tank 100**	Post-Project	**Fixed Roof**														
334	**Tank 107**		90% closed	2	N/A	0	Adjustable - sock	58	N/A	0	N/A	0	N/A	0	AP-42 Default		
440	Tank 110		90% closed	1	N/A	0	Adjustable - sock	58	N/A	0	N/A	0	N/A	0	AP-42 Default		
108	**Tank 153**	Post-Project - Exempt	**Fixed Roof**														
50007	Tank 224		Fixed Roof														

Notes:

[1] Tank parameters for baseline and post-project scenarios based on engineering design. Bold font indicates a parameter that changed between the baseline and post-project scenarios.

Stationary Source Table 12
Summary of Baseline and Post-Project Stock Properties
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Stock[1]	Crude?	Aqueous?	Chemical Mixture?	RVP	MWL	MWV	Liquid Density	S	Antoine Coeff A	Antoine Coeff B	Antoine Coeff C
Crude-Blended	TRUE	FALSE	FALSE	9.8	207	50	7.1	--	9.5	4,039	--
Gasoline TVP 10.99[2]	FALSE	FALSE	FALSE	--	92	66	5.6	--	2.40	0	--
Gasoline TVP 10.92[2]	FALSE	FALSE	FALSE	--	92	66	5.6	--	2.39	0	--
Gasoline	FALSE	FALSE	FALSE	11	92	66	5.6	2.5	--	--	--
Renewable Feedstock[3]	FALSE	FALSE	FALSE	--	284	284	7.5	--	-9.2	0	--

Notes:

1. Stock parameters obtained from facility's 2019 R12-15 Inventory calculations or based on engineering design.
2. The Antoine A Coefficient was conservatively derived to establish the annual average true vapor pressure at 10.99 and 10.92 psia.
3. The density of Renewable Feedstock was obtained from the manufacturer's SDS. The molecular weight of liquid and vapor states is assumed to be equivalent and was derived using the extended form of the Riazi-Daubert equation, where the mean average boiling point was obtained from Yuan et al (2005) and the specific gravity was obtained from the manufacturer's SDS. The Antoine A Coefficient was conservatively derived to establish the annual average true vapor pressure at 0.0001 psia. This is a conservative estimate of laboratory results which indicated the true vapor pressure is several orders of magnitude smaller.

Abbreviations:

MWL - molecular weight, liquid
MWV - molecular weight, vapor
RVP - Reid Vapor Pressure
S - distillation slope

References

W. Yuan, A.C. Hansen, Q. Zhang, Vapor pressure and normal boiling point predictions for pure methyl esters and biodiesel fuels, Fuel, Volume 84, Issues 7–8,2005, Pages 943-950, https://doi.org/10.1016/j.fuel.2005.01.007. Available online: https://www.sciencedirect.com/science/article/abs/pii/S0016236105000256

Stationary Source Table 13
Summary of Meteorological Data Used in Calculations
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Parameter[1]	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Average Daily Minimum Temperature (°F)	47	45	46	50	53	55	57	57	55	55	51	46	51
Average Daily Maximum Temperature (°F)	57	62	61	66	69	76	79	77	77	74	67	57	68
Average Wind Speed (mi/hr)	4.2	4.6	4.6	5.4	7.0	6.7	6.9	6.2	5.2	4.2	3.6	4.8	5.3
Average Daily Solar Insolation (Btu/ft^2/day)	609	822	1,476	1,689	2,427	2,511	2,549	2,199	1,735	1,362	723	746	1,570
Average Atmospheric Pressure (psi)	15	15	15	15	15	15	15	15	15	15	15	15	15

Notes:

[1] All meteorological data other than solar insolation from 2018 for Rodeo, CA. Solar insolation is from 2018 for Napa, CA.

Abbreviations:

Btu - British Thermal Units
°F - degrees Fahrenheit
ft^2 - square feet
hr - hour
mi - mile(s)
psi - pounds per square inch

Stationary Source Table 14
Summary of Baseline and Post-Project Emissions from Existing Tanks
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Comparison Between Baseline Potential to Emit and Post-Project Potential to Emit

Source Number	Tank Number[1]	Baseline PTE[2]			Post-Project PTE[2]			Net Change in Emissions	
		Stock	Throughput (bbl/yr)	POC Emissions (lb/yr)	Stock	Throughput (bbl/yr)	POC Emissions (lb/yr)	lb/yr	ton/yr
97	Tank 100	Crude-Blended	15,571,000	4,782	Renewable Feedstock	15,571,000	0	-4,782	-2.4
334	Tank 107	Crude-Blended	10,000,000	3,885	Gasoline TVP 10.99	10,000,000	3,333	-552	-0.28
440	Tank 110	Gasoline TVP 10.99	3,600,000	10,699	Gasoline TVP 10.92	6,000,000	10,689	-10	-0.0049

Post-Project Actual Emissions

Source Number	Tank Number[1]	Post-Project Actual[2]		
		Stock	Throughput (bbl/yr)	POC Emissions (lb/yr)
97	Tank 100	Renewable Feedstock	12,600,000	0
334	Tank 107	Renewable Feedstock	7,300,000	479
440	Tank 110	Gasoline	6,000,000	4,658

Notes:

[1] See Stationary Source Tables 10 and 11 for descriptions of tank type and parameters. Any potential emissions from Tank 100 in the post-project scenario would be reported as fugitive leaks.

[2] Stocks and throughput for each scenario based on engineering design as shown in Stationary Source Table 9. Emissions were calculated using AP-42 Chapter 7 methodology. Detailed summaries of the tank parameters, stock parameters, and meteorological data used in these calculations are presented in Stationary Source Tables 9 - 13.

Abbreviations:

bbl - barrel(s)
lb - pound(s)
POC - precursor organic compound(s)
yr - year

References:

US EPA. June 2020. AP-42, Fifth Edition, Volume I. Chapter 7: Liquid Storage Tanks. Available at: https://www3.epa.gov/ttnchie1/ap42/ch07/. Accessed March 2021.

Stationary Source Table 15
Summary of Post-Project Emissions from Existing Exempt Tanks
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Tank Number[1]	Post-Project Actuals[2]		
		Stock	Throughput (bbl/yr)	POC Emissions (lb/yr)
108	Tank 153	Renewable Feedstock	7,300,000	140
50007	Tank 224	Renewable Feedstock	3,500,000	0

Notes:

[1] See Stationary Source Tables 10 and 11 for descriptions of tank type and parameters. Any potential emissions from Tank 224 in the post-project scenario are reported as fugitive leaks.

[2] Stocks and throughput for the post-project scenario based on engineering design as shown in Stationary Source Table 9. These exempt tanks are not subject to throughput limits, thus the post-project actual emissions are presented in this table rather than post-project potential to emit. These tanks are instead subject to a mass emission limit of 5 tons per year in order to remain exempt per the requirements of BAAQMD Regulation 2 Rule 1 Section 319.1. Emissions were calculated using AP-42 Chapter 7 methodology. Detailed summaries of the tank parameters, stock parameters, and meteorological data used in these calculations are presented in Stationary Source Tables 9 - 13.

Abbreviations:

bbl - barrel(s)
lb - pound(s)
POC - precursor organic compound(s)
yr - year

References:

US EPA. June 2020. AP-42, Fifth Edition, Volume I. Chapter 7: Liquid Storage Tanks. Available at: https://www3.epa.gov/ttnchie1/ap42/ch07/. Accessed March 2021.

Marine Emissions

Project:	**Phillips66 Rodeo Renewed Project**
Year:	3 year average (2017, 2018, 2019)
Location:	Rodeo Site, San Francisco Refinery, Rodeo, CA

Key tables	Notes
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Marine Table 2. Baseline Emissions per Call by Vessel Type - including Tugs	
Marine Table 3. Baseline Total Annual Emissions by Vessel Category	
Marine Table 4. Deadweight Tonnage and Average Build Time by Vessel Type	
Marine Table 5. Summary of Baseline Vessel Traffic and Tier Mix	
Marine Table 6. Average Call Durations at Berth and During Anchorage	
Marine Table 7. OGV Main Engine Rated Power and Vessel Speed	
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Marine Table 19. Fuel Consumption Emission Factors by Engine and Fuel Type	
Marine Table 20. Fuel Consumption by Engine Type	

Nomenclature:

OGV: ocean going vessels (tankers, ATB barges)
HC: harbor craft (i.e. assist tugs, tow tugs)

Marine Table 1. Baseline Emissions per Call by Vessel Type - Transit and Hotelling Only

			Emissions per Call (lbs/call)										
Year	**Vessel Type**	**No. of Calls**	**PM10**	**PM2.5**	**DPM**	**NOx**	**SOx**	**CO**	**HC**	**VOC**	**CO2**	**CH4**	**N2O**
3YearAvg	Tanker - Smallest	4	10.55	9.93	6.03	452.31	31.38	35.12	19.60	20.64	47368.72	0.39	3.25
3YearAvg	Tanker - Handysize	2	29.00	27.30	16.06	1361.68	89.76	115.58	42.70	44.96	135476.82	0.99	9.39
3YearAvg	Tanker - Handymax	45	52.45	49.37	28.18	2078.10	163.05	193.08	83.48	87.90	246072.52	1.82	17.18
3YearAvg	Tanker - Panamax	7	47.99	45.16	27.36	2098.34	144.75	170.14	89.05	93.77	218484.87	1.85	15.12
3YearAvg	Tanker - Aframax	6	39.49	37.17	24.26	1934.10	117.57	161.57	66.97	70.52	177502.85	1.56	12.08
3YearAvg	Tanker - Suezmax	16	95.63	90.00	53.91	3920.18	290.91	356.75	160.77	169.30	439064.05	3.47	30.35
3YearAvg	ATB Barge	21	6.49	5.97	6.49	400.36	8.69	201.85	19.42	20.45	102871.79	1.19	4.86
3YearAvg	Barge	69	1.00	0.92	1.00	77.53	0.24	53.94	3.10	3.27	21380.28	0.24	1.02

Note:

Emissions per call based on transit and hotelling only, excludes anchorage and tugs

Marine Table 2. Baseline Emissions per Call by Vessel Type - including Tugs

			Emissions per Call (lbs/call)										
Year	**Vessel Type**	**No. of Calls**	**PM10**	**PM2.5**	**DPM**	**NOx**	**SOx**	**CO**	**HC**	**VOC**	**CO2**	**CH4**	**N2O**
3YearAvg	Tanker - Smallest	4	33.75	31.27	29.23	1074.21	31.98	487.19	87.50	85.12	99607.44	1.13	5.74
3YearAvg	Tanker - Handysize	2	52.20	48.64	39.26	1983.57	90.35	567.65	110.60	109.45	187715.55	1.73	11.88
3YearAvg	Tanker - Handymax	45	75.65	70.71	51.38	2699.99	163.64	645.15	151.38	152.39	298311.25	2.56	19.67
3YearAvg	Tanker - Panamax	7	71.18	66.50	50.56	2720.23	145.34	622.21	156.96	158.26	270723.59	2.59	17.61
3YearAvg	Tanker - Aframax	6	62.69	58.51	47.46	2556.00	118.16	613.64	134.88	135.01	229741.57	2.30	14.56
3YearAvg	Tanker - Suezmax	16	119.21	111.70	77.50	4552.45	291.51	816.36	229.81	234.86	492174.53	4.23	32.87
3YearAvg	ATB Barge	21	18.09	16.64	18.09	711.31	8.99	427.89	53.37	52.69	128991.15	1.56	6.10
3YearAvg	Barge	69	19.14	17.61	19.14	568.60	0.71	411.79	56.86	54.32	62717.18	0.82	2.98

Note:

Emissions per call based on transit and hotelling only with tug assists, excludes anchorage

Marine Table 3. Baseline Total Annual Emissions by Vessel Category

	Annual Emissions (tons/year)										
CATEGORY	**PM10**	**PM2.5**	**DPM**	**NOx**	**SOx**	**CO**	**HC**	**VOC**	**CO2**	**CH4**	**N2O**
Barge and tugs - Transit	0.7698	0.7082	0.7698	21.0708	0.1005	15.1603	2.2534	2.1443	1934.0215	0.0274	0.0915
Barge and tugs - Hotelling	0.0805	0.0741	0.0805	6.0166	0.0184	3.5415	0.2688	0.2830	1622.0542	0.0179	0.0771
Tankers with assist tugs - Transit	1.4656	1.3597	1.4593	69.9179	1.1701	21.0887	4.0125	3.9435	4160.7340	0.0673	0.2076
Tankers with assist tugs - Hotelling	1.7842	1.6792	0.7646	50.0869	5.9448	5.6974	2.5488	2.6839	8968.8708	0.0510	0.6492
TOTAL	**4.1001**	**3.8212**	**3.0742**	**147.0921**	**7.2338**	**45.4879**	**9.0835**	**9.0548**	**16685.6805**	**0.1636**	**1.0255**

Marine Table 4. Deadweight Tonnage and Average Build Time by Vessel Type

Tanker Class	Deadweight tonnage Minimum	Deadweight tonnage Maximum	Average Build Time
Tanker - Smallest	-	4,999	1
Tanker - Small	5,000	9,999	0
Tanker - Handysize	10,000	19,999	1
Tanker - Handymax	20,000	59,999	1
Tanker - Panamax	60,000	79,999	1
Tanker - Aframax	80,000	119,999	1
Tanker - Suezmax	120,000	199,999	2

Note:

DWT Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table 3.4 Oil Tankers

Average Build Time Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table C.5 Oil Tankers

Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P10102U0.pdf

Marine Table 5. Summary of Baseline Vessel Traffic and Tier Mix

Year	Vessel Type	Total Vessel Activity		by Engine Tier Calls - Berthing				Slide Valves		by Engine Tier Calls - Anchorage				Slide Valves - Anchored Vessels	
		Calls to Berth	**Calls to Anchorage**	**Tier 0**	**Tier 1**	**Tier 2**	**Tier 3**	**With**	**Without**	**Tier 0**	**Tier 1**	**Tier 2**	**Tier 3**	**With**	**Without**
3YearAvg	Tanker - Smallest	4	0	3	1	0	0	0	4	0	0	0	0	0	0
3YearAvg	Tanker - Handysize	2	2	2	0	0	0	2	0	2	0	0	0	2	0
3YearAvg	Tanker - Handymax	45	26	4	26	15	0	30	15	2	15	9	0	17	9
3YearAvg	Tanker - Panamax	7	3	0	7	0	0	2	5	0	3	0	0	1	2
3YearAvg	Tanker - Aframax	6	0	0	3	3	0	4	2	0	0	0	0	0	0
3YearAvg	Tanker - Suezmax	16	9	1	8	7	0	9	7	1	4	4	0	5	4
3YearAvg	Barge	69	2	1	7	1	60	0	0	0	0	0	2	0	0
3YearAvg	ATB Barge	21	0	0	2	0	19	0	0	0	0	0	0	0	0
3YearAvg	**Total**	**170**	**42**	**11**	**54**	**26**	**79**	**47**	**33**	**5**	**23**	**13**	**2**	**25**	**15**

Note:

Activity Calls to Berth are Provided by p66

Tier Split is based on Baseline Tier Vessel Mix for Applicable Vessel Types

Marine Table 6. Average Call Durations at Berth and During Anchorage

		Annual Average	
Year	**Vessel Type**	**Hotelling Time at Berth (hr/call)**	**Time at Anchorage (hr/call)**
3YearAvg	Tanker - Smallest	42	0.0
3YearAvg	Tanker - Handysize	35	2.7
3YearAvg	Tanker - Handymax	48	2.9
3YearAvg	Tanker - Panamax	45	3.4
3YearAvg	Tanker - Aframax	32	0.0
3YearAvg	Tanker - Suezmax	33	3.3
3YearAvg	Barge	24	3.4
3YearAvg	ATB Barge	41	0.0

Source:

Average duration per vessel type derived from annual vessel call data information for 2019, provided by P66 marine terminal operator

Marine Table 7. OGV Main Engine Rated Power and Vessel Speed

		Annual Average	OGV Maximum Rated Vessel Speed
Year	Vessel Type	Main Eng Avg (kW)	Speed (knots)
3YearAvg	Tanker - Smallest	1,679	14
3YearAvg	Tanker - Handysize	5,475	15
3YearAvg	Tanker - Handymax	8,861	16
3YearAvg	Tanker - Panamax	11,679	16
3YearAvg	Tanker - Aframax	13,415	16
3YearAvg	Tanker - Suezmax	18,941	16
3YearAvg	Barge	0	0
3YearAvg	ATB Barge	3,401	15

Note:

Main engine average kW based on ship data provided by P66 averaged over vessel type

Vessel Speed Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table C.1 Oil/Chemical Tankers, Panamax is based on Bulk Carrier Panamax

Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P10102U0.pdf

Barges are not self-propelled; no propulsion engines.

Marine Table 8. OGV Average Aux Engine & Aux Boiler Loads

Vessel Type	Engine Type	Average Loads (kW)			
		Transit	Maneuvering	Berthing	Anchorage
Tanker - Smallest	Auxiliary Engine	132	182	143	143
Tanker - Smallest	Auxiliary Boiler	0	0	358	55
Tanker - Handysize	Auxiliary Engine	453	622	490	490
Tanker - Handysize	Auxiliary Boiler	0	0	1,226	189
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Panamax	Auxiliary Engine	562	772	609	609
Tanker - Panamax	Auxiliary Boiler	0	0	1,521	234
Tanker - Aframax	Auxiliary Engine	585	805	634	634
Tanker - Aframax	Auxiliary Boiler	0	0	1,586	244
Tanker - Suezmax	Auxiliary Engine	1,548	2,129	1,677	1,677
Tanker - Suezmax	Auxiliary Boiler	0	0	4,193	645
Barge	Auxiliary Engine	40	40	70	70
Barge	Pump Generator	0	0	547	0
ATB Barge	Auxiliary Engine	439	439	761	761
ATB Barge	Pump Generator	0	0	711	0

Note:

Tanker loads based on ship engine data and load factors from ARB

🟦 Pump sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by barge pump load factor (CARB)

🟧 Barge Aux engine sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by barge generator load factor (CARB)

🟥 Aux engine sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by ocean tug auxiliay engine load factor during transit (CARB)

Marine Table 9. Auxiliary Engine and Boiler Load Factors for Tankers

Mode	Auxiliary Engine	Auxiliary Boiler
Transit	0.24	0
Maneuvering	0.33	0
Anchorage	0.26	0.1
Berthing	0.26	0.65

Note:

ARB Marine Emissions Model v2.3L

Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road

Appendix D Emissions Estimation Methodology for Ocean-Going Vessels Table II-10, ARB 2011

Available at: https://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf

Marine Table 10. Load Factors for Barges Auxiliary Engines and Pumps

Source Type	Aux Engine load factor
Pump	0.71
Generator	0.75
Ocean Tug	0.43

Note:

Pump and Generator Source: MSEI CARB Off-road Model - Barge and Dredge

Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road

Ocean Tug Source: San Pedro Bay Ports Emissions Inventory Methodology Report April 2019, Table 3.1.

Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-

Marine Table 11. OGV Transit Speed (knots) by Vessel Type

Year	Vessel Type	Anchorage	Berthing	Manuevering	Light 8 EastBound Route to Maneuvering	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge	Pilot Station Sea Buoy to Outer Ring of Bouys
3YearAvg	Tanker - Smallest	0	0	5	8	10	12	12
3YearAvg	Tanker - Handysize	0	0	5	8	10	12	12
3YearAvg	Tanker - Handymax	0	0	5	8	10	12	12
3YearAvg	Tanker - Panamax	0	0	5	8	10	12	12
3YearAvg	Tanker - Aframax	0	0	5	8	10	12	12
3YearAvg	Tanker - Suezmax	0	0	5	8	10	12	12
3YearAvg	Barge	0	0	5	8	10	12	12
3YearAvg	ATB Barge	0	0	5	8	10	12	12

Sources: ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June

Marine Table 12. OGV Transit Distance (nm) by Vessel Type

Year	Vessel Type	Anchorage	Berthing	Manuevering	Light 8 EastBound Route to Maneuvering	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge	Pilot Station Sea Buoy to Outer Ring of Bouys
3YearAvg	Tanker - Smallest	0	0	0.2	11.79	19	10	6.5
3YearAvg	Tanker - Handysize	0	0	0.2	11.79	19	10	6.5
3YearAvg	Tanker - Handymax	0	0	0.2	11.79	19	10	6.5
3YearAvg	Tanker - Panamax	0	0	0.2	11.79	19	10	6.5
3YearAvg	Tanker - Aframax	0	0	0.2	11.79	19	10	6.5
3YearAvg	Tanker - Suezmax	0	0	0.2	11.79	19	10	6.5
3YearAvg	Barge	0	0	0.2	11.79	19	10	6.5
3YearAvg	ATB Barge	0	0	0.2	11.79	19	10	6.5

Sources: ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June

🟩 Moffat and Nichol, ENVIRON. 2010. Port of Richmond 2005 Seaport Air Emissions Inventory. June

Marine Table 13. Barge auxiliary engines and pump composite emission factors

Year	Engine Type	Horsepower	Horsepower Bin	Tier level mix				Composite Emission Factors (g/hp-hr)				
				Tier 0	Tier 1	Tier 2	Tier 3	VOC	CO	NOx	PM10	PM2.5
3YearAvg	Auxiliary - Barge	63	50<HP<=120	1%	10%	1%	87%	0.10	3.07	2.68	0.04	0.03
3YearAvg	Auxiliary - ATB	685	500<HP<=750	0%	10%	0%	90%	0.09	0.96	1.85	0.03	0.02
3YearAvg	Pump - Barge	515	500<HP<=750	1%	10%	1%	87%	0.07	0.94	1.62	0.02	0.02
3YearAvg	Pump - ATB Barge	670	500<HP<=750	0%	10%	0%	90%	0.09	0.96	1.85	0.03	0.02

Note:

MSEI CARB Off-Road Model - Barge and Dredge

Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road

Average model year assumed based on Tier level information, conservatively as first phase in year

Marine Table 14. Main Engine Fleet-wide Emission Factors

Year	Vessel Type	Emission Factors (g/kW-hr) - Weighted										
		PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
3YearAvg	Tanker - Smallest	0.255	0.240	0.255	16.753	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Tanker - Handysize	0.255	0.240	0.255	17.010	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Tanker - Handymax	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Tanker - Panamax	0.255	0.240	0.255	15.980	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Tanker - Aframax	0.255	0.240	0.255	15.180	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Tanker - Suezmax	0.255	0.240	0.255	15.344	0.389	1.400	0.600	0.632	589.000	0.012	0.029
3YearAvg	Barge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3YearAvg	ATB Barge	0.094	0.086	0.094	2.936	0.426	1.166	0.151	0.159	649.000	0.010	0.029

Notes:

By Tier emission factors from San Pedro Bay Ports Emission Inventory Methodology Report Version 1-2019, Tables 2.3 and 2.4. April 2019.

Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg

Emission factors shown represent Tier mix for category

Slow speed diesel: engine speed < 150 rpm; assumed as default for propulsion engines for tankers and medium speed diesel for ATB Barges

Marine Table 15. Auxiliary Engine Fleet-wide Emission Factors

Year	Vessel Type	Emission Factors (g/kW-hr) - Weighted										
		PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
3YearAvg	Tanker - Smallest	0.255	0.240	0.255	13.420	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Tanker - Handysize	0.255	0.240	0.255	13.820	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Tanker - Handymax	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Tanker - Panamax	0.255	0.240	0.255	12.220	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Tanker - Aframax	0.255	0.240	0.255	11.375	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Tanker - Suezmax	0.255	0.240	0.255	11.581	0.455	1.400	0.600	0.632	686.000	0.012	0.029
3YearAvg	Barge	0.050	0.046	0.050	3.590	0.007	4.121	0.127	0.134	652.000	0.007	0.031
3YearAvg	ATB Barge	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031

Note:

San Pedro Bay Ports Emission Inventory Methodology Report Version 1-2019, Tables 2.9 and 2.10. April 2019.

Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg

Emission factors shown represent Tier mix for category

VOC/HC Conversion Factor for Diesel Off-Road Engines: Conversion Factors for Hydrocarbon Emission Components (EPA-420-R-05-015, December 2005)

Barge tug emission factors are used to estimate Sox and GHG emission factors for barges

Tanker auxiliary engines are medium speed.

Marine Table 16. Harbor Craft Tug Characteristics by Vessel Type

Year	Vessel type	HC Classification	Engine Type	Engine Count per HC (total installed power already considered)	HC Average MY	HC Average HP	HC Average kW	Load Factor	Tugs per call
3YearAvg	Tanker - Smallest	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
3YearAvg	Tanker - Smallest	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
3YearAvg	Tanker - Handysize	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
3YearAvg	Tanker - Handysize	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
3YearAvg	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
3YearAvg	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
3YearAvg	Tanker - Panamax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
3YearAvg	Tanker - Panamax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
3YearAvg	Tanker - Aframax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
3YearAvg	Tanker - Aframax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
3YearAvg	Tanker - Suezmax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	3
3YearAvg	Tanker - Suezmax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	3
3YearAvg	ATB Barge	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	1
3YearAvg	ATB Barge	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	1
3YearAvg	Barge	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	1
3YearAvg	Barge	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	1
3YearAvg	Barge	Tugboat	Propulsion - Tug	1	2007	4,474	3,338	0.31	1
3YearAvg	Barge	Tugboat	Auxiliary - Tug	1	2007	444	331	0.43	1

Note:

ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June

Conservatively assumed oldest Tier 2 engines (MY2007), consistent with Marine Terminal III Project (ERM, 2016)

Load factors from San Pedro Ports Emissions Inventory Methodology Report. https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg

Marine Table 17. Harbor Craft time required to assist vessel (hr/one-way trip)

Tug Type	Maneuvering	Light 8 EastBound Route to Maneuvering + between Jobs transit	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge + Travel to Vessel	Pilot Station Sea Buoy to Outer Ring of Bouys	Manuevering percent, time allocation
Barge Assist	0.29	5.08	1.90	1.42	0.00	3.3%
Barge Tug	0.29	1.47	1.90	0.83	0.54	5.8%

Note:

ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June

1. The between jobs transit accounts for a tug leaving after vessel tied to wharf and one coming back before vessel leaving wharf. For large vessels there
2. The estimated travel time between jobs was assumed to be estimated from a tug home base just off of Angel Island.

Marine Table 18. Harbor Craft Tug Emission Factors

Year	Engine Type	Emission Factors (g/kW-hr)									
		PM10	PM2.5	DPM	NOX	SOX	CO	VOC	CO2	CH4	N2O
3YearAvg	Propulsion	0.290	0.266	0.000	7.796	0.007	5.65	0.81	652.00	0.01	0.03
3YearAvg	Auxiliary	0.287	0.264	0.000	6.924	0.007	5.39	0.75	652.00	0.01	0.03
3YearAvg	Propulsion - Tug	0.290	0.266	0.000	7.796	0.007	5.65	0.81	652.00	0.01	0.03
3YearAvg	Auxiliary - Tug	0.213	0.196	0.000	7.146	0.007	5.61	0.80	652.00	0.01	0.03

Note:

ARB Harbor Craft Emissions Inventory Database

Available at: http://www.arb.ca.gov/msei/california_harbor_craft_emissions_inventory_database_10072011.mdb

Additional tugobat is used to haul barges

Marine Table 19. Fuel Consumption Emission Factors by Engine and Fuel Type

Engine	Engine Speed	Fuel Consumption (g/kw-hr)	Fuel Type
Main	Slow	185	Marine Distilate
Aux	Any	217	Marine Distilate
Boiler	Any	305	Residual Fuel Oil
Assist Tugboat - Auxiliary	Any	137	ULSD
Assist Tugboat - Propulsion	Any	137	ULSD
Tugboat - Auxiliary - Tug	Any	137	ULSD
Tugboat - Propulsion - Tug	Any	137	ULSD

Note:

OGV Source: Appendix D Emissions Estimation Methodology for Ocean-Going Vessels Table II-10, ARB 2011

Available at: https://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf

HC Source: Appendix B Emissions EstimationMethodology for Commercial Harbor Craft Operating in California, ARB

Available at: https://www.arb.ca.gov/msei/chc-appendix-b-emission-estimates-ver02-27-2012.pdf

Marine Table 20. Fuel Consumption by Engine Type

Engine Type	Year	Sum of Kw-Hrs	Fuel Consumption (g)	Fuel Density (g/gal)	Fuel Consumption (gal)
Assist Tugboat - Auxiliary	3YearAvg	178,763	24,527,832	3,180	7,713
Assist Tugboat - Propulsion	3YearAvg	4,373,707	600,111,922	3,180	188,714
Aux	3YearAvg	4,297,295	932,512,988	3,407	273,715
Boiler	3YearAvg	6,842,915	2,087,089,202	3,483	599,294
Main	3YearAvg	2,509,320	464,224,174	3,407	136,261
Pump Generator	3YearAvg	1,494,778	-	-	-
Tugboat - Auxiliary - Tug	3YearAvg	88,388	12,127,660	3,180	3,814
Tugboat - Propulsion - Tug	3YearAvg	642,097	88,101,493	3,180	27,705
3YearAvg Total		**20,427,263**	**-**	**-**	**1,237,217**

Marine Emissions

Project: **Phillips66 Rodeo Renewed Project**
Year: Future
Location: Rodeo Site, San Francisco Refinery, Rodeo, CA

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Nomenclature:
OGV: ocean going vessels (tankers, ATB barges)
HC: harbor craft (i.e. assist tugs, tow tugs)

Marine Table 21. Future Emissions per Call by Vessel Type - Transit and Hotelling Only

			Emissions per Call (lbs/call)										
Year	Vessel Type	No. of Calls	PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
Future	Tanker - Handymax 8	28	50.56	47.59	27.37	2024.99	156.75	187.05	80.78	85.06	236574.83	1.76	16.50
Future	Tanker - Handymax 7	32	53.08	49.96	28.45	2095.83	165.15	195.10	84.38	88.85	249243.99	1.83	17.41
Future	Tanker - Handymax 6	24	31.03	29.20	19.00	1475.99	91.67	124.68	52.87	55.68	138388.86	1.20	9.39
Future	Tanker - Handymax 5	18	37.33	35.13	21.70	1653.09	112.67	144.80	61.88	65.16	170061.75	1.38	11.68
Future	Tanker - Handymax 4	4	55.37	52.12	29.44	2160.23	172.78	202.41	87.65	92.30	260761.41	1.90	18.25
Future	Tanker - Handymax 3	46	19.69	18.53	14.14	1157.22	53.88	88.46	36.67	38.62	81377.65	0.88	5.26
Future	Tanker - Handymax 2	42	21.45	20.19	14.90	1206.81	59.76	94.10	39.19	41.27	90246.06	0.93	5.90
Future	Tanker - Handymax 1	7	26.50	24.94	17.06	1348.81	76.59	110.23	46.41	48.87	115641.96	1.07	7.74
Future	ATB Barge small 4	34	3.28	3.02	3.28	167.69	8.00	80.76	8.23	8.67	41820.50	0.51	1.96
Future	ATB Barge small 3	34	3.83	3.52	3.83	207.64	8.12	101.56	10.15	10.69	52304.79	0.63	2.45
Future	ATB Barge small 2	40	3.91	3.60	3.91	213.79	8.13	104.76	10.45	11.00	53917.75	0.65	2.53
Future	ATB Barge small 1	6	4.26	3.92	4.26	238.94	8.21	117.84	11.66	12.27	60516.26	0.72	2.84
Future	ATB Barge large 2	29	6.21	5.71	6.21	357.75	10.93	177.62	17.42	18.35	91004.07	1.07	4.28
Future	ATB Barge large 1	18	7.07	6.50	7.07	420.02	11.11	210.03	20.42	21.50	107342.76	1.25	5.06

Note:

Emissions per call based on transit and hotelling only, excludes anchorage and tugs

Marine Table 22. Future Emissions per Call by Vessel Type - including Tugs

			Emissions per Call (lbs/call)										
Year	Vessel Type	No. of Calls	PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
Future	Tanker - Handymax 8	28	73.76	68.93	50.57	2646.89	157.34	639.12	148.68	149.54	288813.56	2.50	18.98
Future	Tanker - Handymax 7	32	76.28	71.30	51.65	2717.72	165.74	647.17	152.28	153.34	301482.71	2.57	19.90
Future	Tanker - Handymax 6	24	54.23	50.54	42.20	2097.89	92.26	576.75	120.78	120.16	190627.58	1.94	11.87
Future	Tanker - Handymax 5	18	60.53	56.47	44.90	2274.98	113.26	596.87	129.78	129.64	222300.48	2.12	14.17
Future	Tanker - Handymax 4	4	78.57	73.46	52.63	2782.12	173.38	654.49	155.55	156.78	313000.13	2.64	20.73
Future	Tanker - Handymax 3	46	42.88	39.87	37.34	1779.11	54.48	540.53	104.58	103.10	133616.37	1.62	7.75
Future	Tanker - Handymax 2	42	44.65	41.53	38.10	1828.70	60.35	546.17	107.10	105.76	142484.78	1.67	8.39
Future	Tanker - Handymax 1	7	49.70	46.29	40.26	1970.70	77.19	562.30	114.31	113.36	167880.69	1.81	10.23
Future	ATB Barge small 4	34	14.88	13.69	14.88	478.63	8.29	306.80	42.18	40.91	67939.86	0.88	3.20
Future	ATB Barge small 3	34	15.43	14.19	15.43	518.59	8.41	327.59	44.10	42.93	78424.15	1.00	3.70
Future	ATB Barge small 2	40	15.51	14.27	15.51	524.74	8.43	330.79	44.40	43.24	80037.12	1.02	3.77
Future	ATB Barge small 1	6	15.86	14.59	15.86	549.89	8.51	343.88	45.61	44.52	86635.62	1.09	4.09
Future	ATB Barge large 2	29	17.81	16.38	17.81	668.70	11.22	403.66	51.37	50.59	117123.43	1.44	5.52
Future	ATB Barge large 1	18	18.67	17.17	18.67	730.97	11.41	436.06	54.37	53.74	133462.13	1.62	6.30

Note:

Emissions per call based on transit and hotelling only with tug assists, excludes anchorage

Marine Table 23. Future Total Annual Emissions by Vessel Category

	Annual Emissions (tons/year)										
CATEGORY	PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
Barge and tugs - Transit	1.11	1.02	1.11	31.46	0.70	20.97	3.06	2.94	3895.20	0.06	0.18
Barge and tugs - Hotelling	0.19	0.18	0.19	13.91	0.04	7.24	0.67	0.70	3649.51	0.04	0.17
Tankers with assist tugs - Transit	3.40	3.15	3.39	154.01	2.37	51.52	9.25	9.04	9422.20	0.15	0.47
Tankers with assist tugs - Hotelling	2.37	2.23	1.02	66.58	7.89	7.56	3.38	3.56	11907.86	0.07	0.86
TOTAL	**7.07**	**6.57**	**5.70**	**265.97**	**11.01**	**87.29**	**16.36**	**16.24**	**28874.76**	**0.31**	**1.68**

Marine Table 24. Deadweight Tonnage and Average Build Time by Vessel Type

Tanker Class	Deadweight tonnage Minimum	Deadweight tonnage Maximum	Average Build Time
Tanker - Smallest	-	4,999	1
Tanker - Small	5,000	9,999	0
Tanker - Handysize	10,000	19,999	1
Tanker - Handymax	20,000	59,999	1
Tanker - Panamax	60,000	79,999	1
Tanker - Aframax	80,000	119,999	1
Tanker - Suezmax	120,000	199,999	2

Note:

DWT Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table 3.4 Oil Tankers

Average Build Time Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table C.5 Oil Tankers

Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P10102U0.pdf

Marine Table 25. Summary of Future Vessel Traffic and Tier Mix

Year	Vessel Type	Total Vessel Activity		by Engine Tier Calls - Berthing				Slide Valves		by Engine Tier Calls - Anchorage				e Valves - Anchored Ve	
		Calls to Berth	Calls to Anchorage	Tier 0	Tier 1	Tier 2	Tier 3	With	Without	Tier 0	Tier 1	Tier 2	Tier 3	With	Without
Future	Tanker - Handymax 8	7	3	1	4	2	0	5	2	0	2	1	0	2	1
Future	Tanker - Handymax 7	42	21	4	24	14	0	28	14	2	12	7	0	14	7
Future	Tanker - Handymax 6	46	22	4	27	15	0	31	15	2	13	7	0	15	7
Future	Tanker - Handymax 5	4	2	0	2	1	0	3	1	0	1	1	0	1	1
Future	Tanker - Handymax 4	18	9	2	10	6	0	12	6	1	5	3	0	6	3
Future	Tanker - Handymax 3	24	12	2	14	8	0	16	8	1	7	4	0	8	4
Future	Tanker - Handymax 2	32	16	3	18	11	0	21	11	1	9	5	0	10	5
Future	Tanker - Handymax 1	28	14	2	16	9	0	19	9	1	8	5	0	9	5
Future	ATB Barge small 4	6	0	0	1	0	5	0	0	0	0	0	0	0	0
Future	ATB Barge small 3	40	0	0	4	0	36	0	0	0	0	0	0	0	0
Future	ATB Barge small 2	34	0	0	3	0	31	0	0	0	0	0	0	0	0
Future	ATB Barge small 1	34	0	0	3	0	31	0	0	0	0	0	0	0	0
Future	ATB Barge large 2	18	0	0	2	0	16	0	0	0	0	0	0	0	0
Future	ATB Barge large 1	29	0	0	3	0	26	0	0	0	0	0	0	0	0
Future	**Total**	**362**	**98**	**18**	**131**	**67**	**146**	**134**	**67**	**9**	**57**	**33**	**0**	**65**	**33**

Note:

Activity Calls to Berth are Provided by p66

Tier Split is based on Baseline Tier Vessel Mix for Applicable Vessel Types

Marine Table 26. Average Call Durations at Berth and During Anchorage

			Annual Average - Uncontrolled	
Year	Vessel Type	Parcel size (Bbls)	Hotelling Time at Berth (hr/call)	Time at Anchorage (hr/call)
Future	Tanker - Handymax 8	70,000	18.7	2.9
Future	Tanker - Handymax 7	70,000	13.0	2.9
Future	Tanker - Handymax 6	70,000	11.0	2.9
Future	Tanker - Handymax 5	250,000	51.5	2.9
Future	Tanker - Handymax 4	250,000	31.0	2.9
Future	Tanker - Handymax 3	250,000	23.9	2.9
Future	Tanker - Handymax 2	300,000	48.9	2.9
Future	Tanker - Handymax 1	300,000	46.0	2.9
Future	ATB Barge small 4	80,000	20.5	0.0
Future	ATB Barge small 3	80,000	17.4	0.0
Future	ATB Barge small 2	80,000	16.7	0.0
Future	ATB Barge small 1	80,000	11.7	0.0
Future	ATB Barge large 2	150,000	26.0	0.0
Future	ATB Barge large 1	150,000	21.0	0.0

Source:

Average durations and parcel scenarios at-berth per vessel type forecasted by P66 for the Project

Marine Table 27. OGV Main Engine Rated Power and Vessel Speed

		Annual Average	OGV Maximum Rated Vessel Speed
Year Basis	Vessel Type	Main Eng Avg (kW)	Speed (knots)
Future	Tanker - Handymax	8,861	14
Future	Tanker - Handymax	8,861	15
Future	Tanker - Handymax	8,861	16
Future	Tanker - Handymax	8,861	16
Future	Tanker - Handymax	8,861	16
Future	Tanker - Handymax	8,861	16
Future	ATB Barge small	3,401	0
Future	ATB Barge large	4,474	15

Note:
Main engine average kW based on ship data provided by P66 averaged over vessel type

Vessel Speed Source: Methodologies for Estimating Port-Related and Good Movement Mobile Source Emissions, Table C.1 Oil/Chemical Tankers, Panamax is based on Bulk Carrier Panamax

Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P10102U0.pdf

Marine Table 28. OGV Average Aux Engine & Aux Boiler Loads

Vessel Type	Engine Type	Average Loads (kW)			
		Transit	Maneuvering	Berthing	Anchorage
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
Tanker - Handymax	Auxiliary Engine	621	854	672	672
Tanker - Handymax	Auxiliary Boiler	0	0	1,681	259
ATB Barge small	Auxiliary Engine	439	439	761	761
ATB Barge small	Pump Generator	0	0	711	0
ATB Barge large	Auxiliary Engine	577	577	1,000	1,000
ATB Barge large	Pump Generator	0	0	1,273	0

Note:
Tanker loads based on ship engine data and load factors from ARB

🟦	Pump sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by barge pump load factor (CARB)
🟧	Barge Aux engine sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by barge generator load factor (CARB)
🟥	Aux engine sizes from barge spec sheets (Centerline fleet spec sheets) mutiplied by ocean tug auxiliay engine load factor during transit (CARB)

Marine Table 29. Auxiliary Engine and Boiler Load Factors for Tankers

Mode	Auxiliary Engine	Auxiliary Boiler
Transit	0.24	0
Maneuvering	0.33	0
Anchorage	0.26	0.1
Berthing	0.26	0.65

Note:
ARB Marine Emissions Model v2.3L
Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road
Appendix D Emissions Estimation Methodology for Ocean-Going Vessels Table II-10, ARB 2011
Available at: https://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf

Marine Table 30. Load Factors for Barges Auxiliary Engines and Pumps

Source Type	Aux Engine load factor
Pump	0.71
Generator	0.75
Ocean Tug	0.43

Note:
Pump and Generator Source: MSEI CARB Off-road Model - Barge and Dredge
Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road
Ocean Tug Source: San Pedro Bay Ports Emissions Inventory Methodology Report April 2019, Table 3.1.
Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg

Marine Table 31. OGV Transit Speed (knots) by Vessel Type

Year	Vessel Type	Anchorage	Berthing	Manuevering	Light 8 EastBound Route to Maneuvering	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge	Pilot Station Sea Buoy to Outer Ring of Bouys
Future	Tanker - Smallest	0	0	5	8	10	12	12
Future	Tanker - Handysize	0	0	5	8	10	12	12
Future	Tanker - Handymax	0	0	5	8	10	12	12
Future	Tanker - Panamax	0	0	5	8	10	12	12
Future	Tanker - Aframax	0	0	5	8	10	12	12
Future	Tanker - Suezmax	0	0	5	8	10	12	12
Future	Barge	0	0	5	8	10	12	12
Future	ATB Barge	0	0	5	8	10	12	12

Note:
ATB Barge large and small assumed same transit Speed

Marine Table 32. OGV Transit Distance (nm) by Vessel Type

Year	Vessel Type	Anchorage	Berthing	Manuevering	Light 8 EastBound Route to Maneuvering	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge	Pilot Station Sea Buoy to Outer Ring of Bouys
Future	Tanker - Smallest	0	0	0.2	11.79	19	10	6.5
Future	Tanker - Handysize	0	0	0.2	11.79	19	10	6.5
Future	Tanker - Handymax	0	0	0.2	11.79	19	10	6.5
Future	Tanker - Panamax	0	0	0.2	11.79	19	10	6.5
Future	Tanker - Aframax	0	0	0.2	11.79	19	10	6.5
Future	Tanker - Suezmax	0	0	0.2	11.79	19	10	6.5
Future	Barge	0	0	0.2	11.79	19	10	6.5
Future	ATB Barge	0	0	0.2	11.79	19	10	6.5

Note:
ATB Barge large and small assumed same transit distance

Marine Table 33. Barge auxiliary engines and pump composite emission factors

Year	Engine Type	Horsepower	Horsepower Bin	Tier level mix				Composite Emission Factors (g/hp-hr)				
				Tier 0	Tier 1	Tier 2	Tier 3	VOC	CO	NOx	PM10	PM2.5
Future	Auxiliary - Barge	515	50<HP<=120	1%	10%	1%	87%	0.10	3.07	2.68	0.04	0.03
Future	Auxiliary - ATB small	670	500<HP<=750	0%	10%	0%	90%	0.09	0.96	1.85	0.03	0.02
Future	Pump - ATB Barge small	670	500<HP<=750	1%	10%	1%	87%	0.07	0.94	1.62	0.02	0.02
Future	Pump - ATB Barge large	599	500<HP<=750	0%	10%	0%	90%	0.09	0.96	1.85	0.03	0.02

Note:
MSEI CARB Off-Road Model - Barge and Dredge
Available at: https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road
Average engine age (model year) assumed based on Tier level information from barge spec sheets, conservatively as first phase in year of a specific C2 engine tier level

Marine Table 34. Main Engine Fleet-wide Emission Factors

Year	Vessel Type	Emission Factors (g/kW-hr) - Weighted										
		PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
Future	Tanker - Handymax 8	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 7	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 6	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 5	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 4	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 3	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 2	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	Tanker - Handymax 1	0.255	0.240	0.255	15.538	0.389	1.400	0.600	0.632	589.000	0.012	0.029
Future	ATB Barge small 4	0.094	0.086	0.094	2.936	0.426	1.166	0.151	0.159	649.000	0.010	0.029
Future	ATB Barge small 3	0.094	0.086	0.094	2.936	0.426	1.166	0.151	0.159	649.000	0.010	0.029
Future	ATB Barge small 2	0.094	0.086	0.094	2.936	0.426	1.166	0.151	0.159	649.000	0.010	0.029
Future	ATB Barge small 1	0.094	0.086	0.094	2.936	0.426	1.166	0.151	0.159	649.000	0.010	0.029
Future	ATB Barge large 2	0.093991942	0.086472587	0.093991942	2.936	0.426	1.16584127	0.150640464	0.158624408	649	0.01	0.029
Future	ATB Barge large 1	0.093991942	0.086472587	0.093991942	2.936	0.426	1.16584127	0.150640464	0.158624408	649	0.01	0.029

Notes:
By Tier emission factors from San Pedro Bay Ports Emission Inventory Methodology Report Version 1-2019, Tables 2.3 and 2.4. April 2019.
Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg
Emission factors shown represent Tier mix for category
Slow speed diesel: engine speed < 150 rpm; assumed as default for propulsion engines for tankers and medium speed diesel for ATB Barges

Marine Table 35. Auxiliary Engine Fleet-wide Emission Factors

Year	Vessel Type	Emission Factors (g/kW-hr) - Weighted										
		PM10	PM2.5	DPM	NOx	SOx	CO	HC	VOC	CO2	CH4	N2O
Future	Tanker - Handymax 8	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 7	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 6	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 5	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 4	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 3	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 2	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	Tanker - Handymax 1	0.255	0.240	0.255	11.799	0.455	1.400	0.600	0.632	686.000	0.012	0.029
Future	ATB Barge small 4	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031
Future	ATB Barge small 3	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031
Future	ATB Barge small 2	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031
Future	ATB Barge small 1	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031
Future	ATB Barge large 2	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031
Future	ATB Barge large 1	0.034	0.032	0.034	2.485	0.007	1.293	0.119	0.126	652.000	0.007	0.031

Note:
San Pedro Bay Ports Emission Inventory Methodology Report Version 1-2019, Tables 2.9 and 2.10. April 2019.
Available at: https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg
Emission factors shown represent Tier mix for category
Tanker auxiliary engines are medium speed.

Marine Table 36. Harbor Craft Tug Characteristics by Vessel Type

Year	Vessel type	HC Classification	Engine Type	Engine Count per HC (total installed power already considered)	HC Average MY	HC Average HP	HC Average kW	Load Factor	Tugs per call
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	Tanker - Handymax	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	2
Future	Tanker - Handymax	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	2
Future	ATB Barge small	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	1
Future	ATB Barge small	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	1
Future	ATB Barge large	Assist Tugboat	Propulsion	1	2007	4,344	3,241	0.31	1
Future	ATB Barge large	Assist Tugboat	Auxiliary	1	2007	128	95	0.43	1

Note:
ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June
Conservatively assumed oldest Tier 2 engines (MY2007), consistent with Marine Terminal III Project (ERM, 2016)
Load factors from San Pedro Ports Emissions Inventory Methodology Report. https://kentico.portoflosangeles.org/getmedia/3559520c-b85d-45ad-ad68-9947c34b980d/WV_FINAL_SPBP_Emissions_Inventory-_Methodology_4-25-19_scg

Marine Table 37. HC time required to assist vessel (hr/one-way trip)

Tug Type	Maneuvering	Light 8 EastBound Route to Maneuvering + between Jobs transit	Mile Rock 1 nm west of Golden Gate Bridge to Light 8 EastBound Route	Pilot Station Sea Buoy to Mile Rock 1 nm west of Golden Gate Bridge + Travel to Vessel	Pilot Station Sea Buoy to Outer Ring of Bouys	Manuevering percent, time allocation
Barge Assist	0.29	5.08	1.90	1.42	0.00	0.03
Barge Tug	0.29	1.47	1.90	0.83	0.54	0.03

Note:
ERM. 2016. Estimated Emissions Increases and Human Health Risk Impacts Associated with the Marine Terminal III Project. June
1. The between jobs transit accounts for a tug leaving after vessel tied to wharf and one coming back before vessel leaving wharf. For large vessels there is an extra third
2. The estimated travel time between jobs was assumed to be estimated from a tug home base just off of Angel Island.

Marine Table 38. Harbor Craft Tug Emission Factors

Year	Engine Type	Emission Factors (g/kW-hr)									
		PM10	PM2.5	DPM	NOX	SOX	CO	VOC	CO2	CH4	N2O
Future	Propulsion	0.290	0.266	0.000	7.796	0.007	5.65	0.81	652.00	0.01	0.03
Future	Auxiliary	0.287	0.264	0.000	6.924	0.007	5.39	0.75	652.00	0.01	0.03

Note:
ARB Harbor Craft Emissions Inventory Database
Available at: http://www.arb.ca.gov/msei/california_harbor_craft_emissions_inventory_database_10072011.mdb

Marine Table 39. Fuel Consumption Emission Factors by Engine and Fuel Type

Engine	Engine Speed	Fuel Consumption (g/kw-hr)	Fuel Type
Main	Slow	185	Marine Distilate
Aux	Any	217	Marine Distilate
Boiler	Any	305	Residual Fuel Oil
Assist Tugboat - Auxiliary	Any	137	ULSD
Assist Tugboat - Propulsion	Any	137	ULSD
Tugboat - Auxiliary - Tug	Any	137	ULSD
Tugboat - Propulsion - Tug	Any	137	ULSD

Note:
OGV Source: Appendix D Emissions Estimation Methodology for Ocean-Going Vessels Table II-10, ARB 2011
Available at: https://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf
HC Source: Appendix B Emissions EstimationMethodology for Commercial Harbor Craft Operating in California, ARB
Available at: https://www.arb.ca.gov/msei/chc-appendix-b-emission-estimates-ver02-27-2012.pdf

Marine Table 40. Fuel Consumption by Engine Type

Engine Type	Year	Sum of Kw-Hrs	Fuel Consumption (g)	Fuel Density (g/gal)	Fuel Consumption (gal)
Assist Tugboat - Auxiliary	Future	401,715	55,118,942	3,180	17,333
Assist Tugboat - Propulsion	Future	9,828,594	1,348,571,446	3,180	424,079
Aux	Future	8,171,363	1,773,185,753	3,407	520,473
Boiler	Future	9,102,121	2,776,146,837	3,483	797,152
Main	Future	6,463,100	1,195,673,432	3,407	350,959
Pump Generator	Future	2,641,476	-	-	-
Future Total		**36,608,369**	**-**	**-**	**2,109,997**

Marine Table 41. Future Vessel Activity and Parcel Size

CATEGORIES	Annual calls	Call duration (hr)	Parcel size (Bbls)
Tanker - Handymax 1	7.0	18.7	70,000
Tanker - Handymax 2	42.0	13.0	70,000
Tanker - Handymax 3	46.0	11.0	70,000
Tanker - Handymax 4	4.0	51.5	250,000
Tanker - Handymax 5	18.0	31.0	250,000
Tanker - Handymax 6	24.0	23.9	250,000
Tanker - Handymax 7	32.0	48.9	300,000
Tanker - Handymax 8	28.0	46.0	300,000
ATB Barge small 1	6.0	20.5	80,000
ATB Barge small 2	40.0	17.4	80,000
ATB Barge small 3	34.0	16.7	80,000
ATB Barge small 4	34.0	11.7	80,000
ATB Barge large 1	18.0	26.0	150,000
ATB Barge large 2	29.0	21.0	150,000

Rail Emissions

Project: **Phillips66 Rodeo Renewed Project**
Year: 2017-2019
Location: Butane Loading Rack, San Francisco Refinery, Rodeo, CA

Key Tables	Notes
Rail Table 1. Average Butane Rail Rack Daily Process Parameters for 2017-2019	
Rail Table 2. Average Butane Rail Rack Annual Process Parameters for 2017-2019	
Rail Table 3. Constants and Factors	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 4. Average 2017-2019 Tier Distribution for Locomotive Engines	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 5. Class I Line-Haul Emission Factors (g/bhp-hr)	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 6. Class I Line-Haul Emission Factors (g/gal)	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 7. Average Locomotive Composite Emission Factors for 2017-2019	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 8. Average Consumption of Diesel Fuel for Union Pacific in 2017-2019	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 9. Average Railroad Operating Statistics for Union Pacific in 2017-2019	Table applies to all rail locations in CA in 2017-2019 Average
Rail Table 10. Cargo Handling Equipment Characteristics	
Rail Table 11. Cargo Handling Equipment Emission Factors and Emissions	
Rail Table 12. Summary of Average 2017-2019 Baseline Butane Rail Rack Daily Emissions (lbs/day)	
Rail Table 13. Summary of Average 2017-2019 Baseline Butane Rail Rack Annual Emissions (tons/yr)	

Rail Table 1. Average Butane Rail Rack Daily Process Parameters for 2017-2019

Daily Parameter	Value	Units	Reference & Notes
Number of Tank Cars	5.7	cars/day	Data based on project design basis (P66, 2021)
Butane Average Load per Car (bbl)	733	bbl/car	Data based on project design basis (P66, 2021)
Butane Average Load per Car (gal)	30,803	gal/car	Calculated
Butane Weight per Car	75	short tons/car	Calculated
Butane to be Transported	427	short tons/day	Calculated
Tare Weight of Empty Tank Car	48.8	short tons/car	Ref: Eight-axle tank wagon for oil products, https://www.searates.com/reference/tank/
Daily Weight of Empty Tank Cars	302	tare short tons/day	Calculated Tare Weight
Daily Weight of Filled Tank Cars	729	gross short tons/day	Freight Weight + Tare Weight
Daily CHE Operating Hours	1.00	hr/day	Data based on project design basis (P66, 2021)

Note:
[1] Annual process parameters are used to calculate annual inbound and outbound throughput.

Rail Table 2. Average Butane Rail Rack Annual Process Parameters for 2017-2019

Annual Parameter	Value	Units	Reference & Notes
Number of Tank Cars	1968	cars/year	Data based on project design basis (P66, 2021)
Butane Average Load per Car (bbl)	733	bbl/car	Data based on project design basis (P66, 2021)
Butane Average Load per Car (gal)	30,803	gal/car	Calculated
Butane Weight per Car	75	short tons/car	Calculated
Butane to be Transported	147,306	short tons/year	Calculated
Tare Weight of Empty Tank Car	48.8	short tons/car	Ref: Eight-axle tank wagon for oil products, https://www.searates.com/reference/tank/
Annual Weight of Empty Tank Cars	104,306	tare short tons/year	Calculated Tare Weight
Annual Weight of Filled Tank Cars	251,612	gross short tons/year	Freight Weight + Tare Weight
Annual CHE Operating hours	365	hr/year	Data based on project design basis (P66, 2021)

Note:
[1] Annual process parameters are used to calculate annual inbound and outbound throughput.

Rail Table 3. Constants and Factors

Constants and Factors	Value	Units	Reference & Notes
Density of Butane	4.86	lbs/gal	Ref: Liquified Gas Conversion Chart (LACFD 2018). Available at: https://fire.lacounty.gov/wp-content/uploads/2019/08/Gas_Conversion_Chart.pdf
Net Aggregated Fuel Consumption Index	963	ton-miles/gal	Calculated, includes idling
Percent of Train Weight for Locomotives	8.6%		Calculated
Pound to Gram	453.592	g/lb	
Density of Diesel Fuel	3200	g/gal	Ref: Emission Factors for Locomotives, EPA-420-F-09-025, April 2009. Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100500B.PDF?Dockey=P100500B.PDF
Class I Locomotive Fuel Consumption to Horsepower-Hour Conversion Factor	20.8	(hp-hr/gal)	Ref: Emission Factors for Locomotives (EPA 2009)
Class I Line-haul Brake Specific Fuel Consumption (BSFC)	154	(g/hp·hr)	Ref: Table 8.4., Ports Emissions Inventory Guidance: Methodologies for Estimating Port-Related and Goods Movement Mobile Source Emissions, EPA 2020. Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P10102U0.pdf
Fuel Sulfur Conversion Factor	97.8%		Ref: Emission Factors for Locomotives (EPA 2009)
Sulfur Content of Diesel Fuel	15	ppmw	Ref: California Diesel Fuel Standard (CARB 2014)
Molar Mass of SO_2	64	g/mol SO_2	
Molar Mass of S	32	g/mol S	

Rail Table 4. Average 2017-2019 Tier Distribution for Locomotive Engines

Locomotive Diesel Engines	Percentage
Pre-Tier	0%
Tier 0	0%
Tier 0+	2%
Tier 1	0%
Tier 1+	7%
Tier 2	12%
Tier 2+	33%
Tier 3	32%
Tier 4	14%

Source:

[1] ARB locomotive model, Available at:
https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.xlsx

Rail Table 5. Class I Line-Haul Emission Factors (g/bhp-hr)

Tier Level	PM$_{10}$	HC	NOx	CO	PM$_{2.5}$	VOC	SO$_2$
Pre-Tier	0.32	0.48	13	1.28	0.29	0.51	0.09
Tier 0	0.32	0.48	8.6	1.28	0.29	0.51	0.09
Tier 0+	0.2	0.3	7.2	1.28	0.18	0.32	0.09
Tier 1	0.32	0.47	6.7	1.28	0.29	0.49	0.09
Tier 1+	0.2	0.29	6.7	1.28	0.18	0.31	0.09
Tier 2	0.18	0.26	4.95	1.28	0.17	0.27	0.09
Tier 2+	0.08	0.13	4.95	1.28	0.07	0.14	0.09
Tier 3	0.08	0.13	4.95	1.28	0.07	0.14	0.09
Tier 4	0.015	0.04	1	1.28	0.01	0.04	0.09

Note:

[1]+ Indicates revised standards in 40 CFR Part 1033.
[2] PM$_{2.5}$ emission factor is 92% of PM$_{10}$.
[3] VOC emissions is assumed to be 1.053 times HC emissions (EPA 2009)
[4] Equation 4.5 in 2017 Line haul Locomotive Model & Update.

Source:

[1] Table 4-7, 2017 Line haul Locomotive Model & Update, California Air Resources Board, Off Road Diesel Analysis Section, October 2017. Available at: https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.docx

Rail Table 6. Class I Line-Haul Emission Factors (g/gal)

Tier Level	PM$_{10}$	HC	NOx	CO	PM$_{2.5}$	VOC	SO$_2$
Pre-Tier	6.7	10.0	270.4	26.6	6.1	10.5	2.0
Tier 0	6.7	10.0	178.9	26.6	6.1	10.5	2.0
Tier 0+	4.2	6.2	149.8	26.6	3.8	6.6	2.0
Tier 1	6.7	9.8	139.4	26.6	6.1	10.3	2.0
Tier 1+	4.2	6.0	139.4	26.6	3.8	6.4	2.0
Tier 2	3.7	5.4	103.0	26.6	3.4	5.7	2.0
Tier 2+	1.7	2.7	103.0	26.6	1.5	2.8	2.0
Tier 3	1.7	2.7	103.0	26.6	1.5	2.8	2.0
Tier 4	0.3	0.8	20.8	26.6	0.3	0.9	2.0

Note:

[1] Unit conversion (g/bhp-hr to g/gal) from Rail Table 7.

Rail Table 7. Average Locomotive Composite Emission Factors for 2017-2019

Criteria Pollutants/GHG	Emission Factor (g/gal)	Emission Factor (lb/1000 gal)
PM_{10}	2.0	4.3
$PM_{2.5}$	1.8	4.0
NOx	95.4	210.4
CO	26.6	58.7
VOC	3.3	7.2
SO_2	2.0	4.3

Source:

[1] CAP EF source: Table 4-7, 2017 Line haul Locomotive Model & Update, California Air Resources Board, Off Road Diesel Analysis Section, October 2017. Available at: https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.docx

[2] Tier Distribution Source: CARB locomotive model, https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.xlsx

Rail Table 8. Average Consumption of Diesel Fuel for Union Pacific in 2017-2019

Kind of locomotive service	Diesel oil (gals)
Freight	870,814,873
Yard Switching	83,784,976
Freight and Yard	**954,599,849**

Source:
[1] Table 750. Consumption of Diesel Fuel, Class I Railroad Annual Report R-1, Union Pacific Railroad, 2019. Available at: https://www.up.com/cs/groups/public/@uprr/@investor/documents/investordocuments/pdf_up_r1_2019.pdf

Rail Table 9. Average Railroad Operating Statistics for Union Pacific in 2017-2019

Freight Trains, Cars, Cnts., and Caboose	UP Gross ton-miles (thousands)
Road Locomotives	72,880,060
Freight Trains, Cars, Cnts., and Caboose	248,707,812
Unit Trains	
Way Trains	16,191,415
Through Trains	571,309,960
Non-Revenue	10,406,772
Total	**919,496,019**

Source:
[1] Table 755. Line 98. Railroad Operating Statistics, Class I Railroad Annual Report R-1, Union Pacific Railroad, 2019. Available at: https://www.up.com/cs/groups/public/@uprr/@investor/documents/investordocuments/pdf_up_r1_2019.pdf

Cargo Handling Equipment (Rail Car Mover)

Equipment: Trackmobile Viking T4

130 hp @ 2500 rpm

Rail Table 10. Cargo Handling Equipment Characteristics

Vehicle Category	Model Year	Horsepower Bin	Fuel	Horsepower_Hours_hhpy	Load Factor	Daily CHE Operating Hours
CHE - Rail Other General Industrial Equipment	2018	175	Diesel	9993.7	0.4	1.0
Data Source:	Communication with P66 [1]	CARB OFFROAD2017 (v1.0.1) Emissions Model	Communication with P66 [1]	CARB OFFROAD2017 (v1.0.1) Emissions Model	Other Material Handling Equipment Load Factor. CARB [2]	Communication with P66 [1]

Note:

Emission factors are used in the calculation of daily and annual CHE emissions

Sources:

[1] Data provided by P66 staff. January 2021

[2] Other Material Handling Equipment Load Factor. CARB Appendix D. EMISSIONS INVENTORY DEVELOPMENT FOR IN-USE OFF-ROAD EQUIPMENT. Available at: https://ww3.arb.ca.gov/regact/2010/offroadlsi10/offroadappd.pdf

Rail Table 11. Cargo Handling Equipment Emission Factors and Emissions

Pollutant	Emission Factor (g/hp-hr)	Daily Emissions (lbs/day)	Annual Emissions (tons/year)
NOx	0.132	0.038	6.91E-03
CO	1.411	0.405	7.38E-02
VOC	0.024	0.007	1.24E-03
PM_{10}	0.005	0.001	2.37E-04
$PM_{2.5}$	0.004	0.001	2.18E-04
SO_2	0.002	0.001	1.30E-04

Rail Table 12. Summary of Average 2017-2019 Baseline Butane Rail Rack Daily Emissions (lbs/day)

Pollutant/GHG	BAAQMD	CHE
NOx	7.54E+00	3.79E-02
CO	2.10E+00	4.05E-01
VOC	2.57E-01	6.77E-03
PM_{10}	1.55E-01	1.30E-03
$PM_{2.5}$	1.43E-01	1.20E-03
SO_2	1.54E-01	7.13E-04

BAAQMD: total locomotive emissions within Air District

CHE: total cargo handling equipment emissions

Rail Table 13. Summary of Average 2017-2019 Baseline Butane Rail Rack Annual Emissions (tons/yr)

Pollutant/GHG	BAAQMD	CHE
NOx	1.30E+00	6.91E-03
CO	3.63E-01	7.38E-02
VOC	4.44E-02	1.24E-03
PM_{10}	2.68E-02	2.37E-04
$PM_{2.5}$	2.46E-02	2.18E-04
SO_2	2.66E-02	1.30E-04

Rail Emissions

Project: **Phillips66 Rodeo Renewed Project**
Year: 2017-2019
Location: Carbon Plant, San Francisco Refinery, Rodeo, CA

Key Tables	Notes
Rail Table 14. Average Carbon Plant Rail Rack Daily Process Parameters for 2017-2019	
Rail Table 15. Average Carbon Plant Rail Rack Annual Process Parameters for 2017-2019	
Rail Table 16. Cargo Handling Equipment Characteristics	
Rail Table 17. Cargo Handling Equipment Emission Factors and Emissions	
Rail Table 18. Summary of Average 2017-2019 Baseline Carbon Plant Rail Rack Daily Emissions (lbs/day)	
Rail Table 19. Summary of Average 2017-2019 Baseline Carbon Plant Rail Rack Annual Emissions (tons/yr)	

Rail Table 14. Average Carbon Plant Rail Rack Daily Process Parameters for 2017-2019

Daily Parameter	Value	Units	Reference & Notes
Number of Railcars	2.34	cars/day	3 visits per week/ 7 cars per week on avg (P66, 2021)
Petroleum Coke Weight per Car	90	short tons/car	(P66, 2021)
Petroleum Coke to be Transported	210	short tons/day	Calculated
Tare Weight of Empty Open Wagons	31	short tons/car	Ref: Six-axle all-metal open wagon, https://www.searates.com/reference/open/
Daily Weight of Empty Open Wagons	79	tare short tons/day	Calculated Tare Weight
Daily Weight of Filled Railcars	289	gross short tons/day	Freight Weight + Tare Weight
Daily CHE Operating hours	1.1	hr/day	Calculated from annual, used 3 times per week

Note:

[1] Daily process parameters are used to calculate daily inbound and outbound throughput.

Rail Table 15. Average Carbon Plant Rail Rack Annual Process Parameters for 2017-2019

Annual Parameter	Value	Units	Reference & Notes
Number of Railcars	365	cars/year	Carbon Plant data from P66, 2017-2019 3 year average
Petroleum Coke Weight per Car	90	short tons/car	(P66, 2021)
Petroleum Coke to be Transported	32,820	short tons/year	Calculated
Tare Weight of Empty Open Wagons	31	short tons/car	Ref: Six-axle all-metal open wagon, https://www.searates.com/reference/open/
Annual Weight of Empty Open Wagons	12,278	tare short tons/year	Calculated Tare Weight
Annual Weight of Filled Railcars	45,098	gross short tons/year	Freight Weight + Tare Weight
Annual CHE Operating hours	178	hr/year	Carbon Plant data from P66

Note:

[1] Daily process parameters are used to calculate daily inbound and outbound throughput.

Rail Table 16. Cargo Handling Equipment Characteristics

Vehicle Category	Model Year	Horsepower Bin	Fuel	Horsepower_Hours_hhpy	Load Factor	Daily CHE Operating hours
CHE - Rail Other General Industrial Equipment	2013	300	Diesel	178,031	0.4	0.5
Data Source:	Communication with P66 [1]	CARB OFFROAD2017 (v1.0.1) Emissions Model	Communication with P66 [1]	CARB OFFROAD2017 (v1.0.1) Emissions Model	Other Material Handling Equipment Load Factor. CARB [2]	Communication with P66 [1]

Note:
Emission factors are used in the calculation of daily and annual CHE emissions
Sources:
[1] Data provided by P66 staff. January 2021
[2] Other Material Handling Equipment Load Factor. CARB Appendix D. EMISSIONS INVENTORY DEVELOPMENT FOR IN-USE OFF-ROAD EQUIPMENT. Available at: https://ww3.arb.ca.gov/regact/2010/offroadlsi10/offroadappd.pdf

Rail Table 17. Cargo Handling Equipment Emission Factors and Emissions

Pollutant	Emission Factor (g/hp-hr)	Daily Emissions (lbs/day)	Annual Emissions (tons/year)
NOx	0.780	0.190	3.44E-02
CO	0.519	0.126	2.29E-02
VOC	0.075	0.018	3.30E-03
PM_{10}	0.006	0.001	2.59E-04
$PM_{2.5}$	0.005	0.001	2.38E-04
SO_2	0.002	0.001	1.03E-04
CO_2	253.661	61.65	1.12E+01

Rail Table 18. Summary of Average 2017-2019 Baseline Carbon Plant Rail Rack Daily Emissions (lbs/day)

Pollutant/GHG	BAAQMD	CHE
NOx	2.68E+00	1.90E-01
CO	7.51E-01	1.26E-01
VOC	9.09E-02	1.82E-02
PM_{10}	5.48E-02	1.43E-03
$PM_{2.5}$	5.04E-02	1.31E-03
SO_2	5.50E-02	5.70E-04

BAAQMD: total locomotive emissions within Air District

CHE: total cargo handling equipment emissions

Rail Table 19. Summary of Average 2017-2019 Baseline Carbon Plant Rail Rack Annual Emissions (tons/yr)

Pollutant/GHG	BAAQMD	CHE
NOx	2.09E-01	3.44E-02
CO	5.86E-02	2.29E-02
VOC	7.09E-03	3.30E-03
PM_{10}	4.27E-03	2.59E-04
$PM_{2.5}$	3.93E-03	2.38E-04
SO_2	4.29E-03	1.03E-04

Rail Emissions

Project:	**Phillips66 Rodeo Renewed Project**
Year:	2024 (Project)
Location:	Rodeo Site, Rodeo, CA

Key Tables	**Notes**
Rail Table 20. Rodeo Site Rail Rack Daily Process Parameters for 2024	
Rail Table 21. Rodeo Site Rail Rack Annual Process Parameters for 2024	
Rail Table 22. 2024 Tier Distribution for Locomotive Engines	
Rail Table 23. Composite Emission Factors for Year 2024 for Locomotives	
Rail Table 24. Summary of 2024 Future Rodeo Site Rail Rack Daily Emissions (lbs/day) by AQMD/APCD	
Rail Table 25. Summary of 2024 Future Rodeo Site Rail Rack Annual Emissions (tons/yr) by AQMD/APCD	

Rail Table 20. Rodeo Site Rail Rack Daily Process Parameters for 2024

Daily Parameter	Value	Units	Reference & Notes
Number of Tank Cars	16	cars/day	Based on project design basis (P66, 2021)
Tallow Average Load per Car (bbl)	620	bbl/car	Based on project design basis (P66, 2021)
Tallow Average Load per Car (ft^3)	3,481	ft^3/car	Calculated
Tallow Weight per Car	98	short tons/car	Calculated
Tallow to be Transported	1,568	short tons/day	Calculated
Tare Weight of Empty Tank Car	42.2	short tons/car	Ref: CBTX DOT 111, https://www.gbrx.com/media/1466/tank29000.pdf
Daily Weight of Empty Tank Cars	732	tare short tons/day	Calculated Tare Weight
Daily Weight of Filled Tank Cars	2,300	gross short tons/day	Freight Weight + Tare Weight
Daily CHE Operating Hours	3.4	hr/day	Data based on project design basis (P66, 2021) operations, scaled from baseline based on cars per day

Note:
[1] Daily process parameters are used to calculate daily inbound and outbound throughput.

Rail Table 21. Rodeo Site Rail Rack Annual Process Parameters for 2024

Annual Parameter	Value	Units	Reference & Notes
Number of Tank Cars	5,840	cars/year	Based on project design basis (P66, 2021)
Tallow Average Load per Car (bbl)	620	bbl/car	Based on project design basis (P66, 2021)
Tallow Average Load per Car (ft^3)	3,481	ft^3/car	Calculated
Tallow Weight per Car	98	short tons/car	Calculated
Tallow to be Transported	572,271	short tons/year	Calculated
Tare Weight of Empty Tank Car	42.2	short tons/car	Ref: CBTX DOT 111, https://www.gbrx.com/media/1466/tank29000.pdf
Annual Weight of Empty Tank Cars	267,346	tare short tons/year	Calculated Tare Weight
Annual Weight of Filled Tank Cars	839,617	gross short tons/year	Freight Weight + Tare Weight
Annual CHE Operating Hours	1,243	hr/year	Data based on project design basis (P66, 2021) operations, scaled from baseline based on cars per day

Note:
[1] Annual process parameters are used to calculate annual inbound and outbound throughput.

Rail Table 22. 2024 Tier Distribution for Locomotive Engines

Locomotive Diesel Engines	Percentage
Pre-Tier	0%
Tier 0	0%
Tier 0+	0%
Tier 1	0%
Tier 1+	1%
Tier 2	0%
Tier 2+	13%
Tier 3	32%
Tier 4	53%

Source:

[1] ARB locomotive model, Available at: https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.xlsx

Rail Table 23. Composite Emission Factors for Year 2024 for Locomotives

Criteria Pollutants/GHG	Emission Factor (g/gal)	Emission Factor (lb/1000 gal)
PM_{10}	1.0	2.1
$PM_{2.5}$	0.9	2.0
NOx	59.6	131.4
CO	26.6	58.7
VOC	1.8	4.0
SO_2	2.0	4.3

Source:

[1] CAP EF source: Table 4-7, 2017 Line haul Locomotive Model & Update, California Air Resources Board, Off Road Diesel Analysis Section, October 2017. Available at: https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.docx

[2] Tier Distribution Source: CARB locomotive model, https://ww3.arb.ca.gov/msei/ordiesel/locolinehaul2017ei.xlsx

Rail Table 24. Summary of 2024 Future Rodeo Site Rail Rack Daily Emissions (lbs/day) by AQMD/APCD

Pollutant/GHG	BAAQMD	CHE
NOx	1.39E+01	1.29E-01
CO	6.19E+00	1.38E+00
VOC	4.26E-01	2.30E-02
PM_{10}	2.25E-01	4.43E-03
$PM_{2.5}$	2.07E-01	4.07E-03
SO_2	4.54E-01	2.43E-03

BAAQMD: total locomotive emissions within Air District

CHE: total cargo handling equipment emissions

Rail Table 25. Summary of 2024 Future Rodeo Site Rail Rack Annual Emissions (tons/yr) by AQMD/APCD

Pollutant/GHG	BAAQMD	CHE
NOx	2.53E+00	2.35E-02
CO	1.13E+00	2.51E-01
VOC	7.78E-02	4.21E-03
PM_{10}	4.11E-02	8.08E-04
$PM_{2.5}$	3.78E-02	7.43E-04
SO_2	8.28E-02	4.43E-04

APPENDIX C
PERMIT FEE CALCULATIONS

Table C-1
Permit Fees
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source Number	Source	Permit Status[2]	Number of Units per Source	Filing Fee per Unit	Initial Fee per Unit	Toxic Risk Screening Fee (First Source)	Permit to Operate Fee	Title V Minor Revision Fee[4]	Toxic Surcharge[5]	Total[1]	Basis[3]
New/PTU	Pretreatment Unit (PTU)	New Source	1	$508	$4,992	--	$2,492	$1,718	--	$9,710	Schedule G-1
New/STU	U237 Sulfur Treatment Unit (STU)	New Source	1	$508	$4,992	$5,665	$2,492	$1,718	$249	$15,624	Schedule G-1
307	U240 Unicracking Unit	Altered	1	$508	$36,691	--	--	--	--	$37,199	Schedule G-3
97	Tank 100	Altered	1	$508	$11,577	--	--	$1,718	--	$13,803	Schedule C
334	Tank 107	Altered	1	$508	$6,993	--	--	$1,718	--	$9,219	Schedule C
440	Tank 110	Altered	1	$508	$6,525	--	--	$1,718	--	$8,751	Schedule C
425/426	Marine Terminal Loading Berth M1 and M2	Change of Conditions	1	$0	$0	--	--	$0	--	$0	Fees paid in Application 25608
70	Rail	Exempt	1	$508	--	--	--	--	--	$508	--
108	Tank 153	Exempt	1	$508	--	--	--	--	--	$508	
50007	Tank 224	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Wet Surface Air Cooler	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Dissolved Air Flotation Unit	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Closed-Loop Vapor Recovery for PTU Train 1	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Closed-Loop Vapor Recovery for PTU Train 2	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Closed-Loop Vapor Recovery for PTU Train 3	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Closed-Loop Vapor Recovery for FOG Recovery	Exempt	1	$508	--	--	--	--	--	$508	
New/PTU	Storage Silo (typical of 21)	Exempt	21	$508	--	--	--	--	--	$10,668	
New/PTU	Day Hopper (typical of 13)	Exempt	13	$508	--	--	--	--	--	$6,604	
									Major Facility Review Filing Fee	$1,210	Schedule P
									Total	**$117,360**	--

Notes:

1. Fees were obtained from BAAQMD Regulation 3: Fees. Available at: https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-3-fees/2020-amendment/documents/20200701_01_finalreg_0300-pdf.pdf?la=en. Accessed: May 2021
2. New sources, altered sources, sources with change of conditions, and exempt sources followed the requirements of Regulation 3-302, 3-304, 3-306, and 3-337, respectively.
3. Fees were determined based on the schedule each source was categorized at. Exempt sources will only pay a standard filling fee and do not need to follow a determined schedule.
4. Minor revision fees were based on Schedule P, 3d.
5. Emissions exceed the chronic trigger level listed in Table 2-5-1 for U237. Therefore, the toxic surcharge is equal to 10 percent of the permit to operate fee.