BIOFUELWATCH • CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE • CENTER FOR BIOLOGICAL DIVERSITY • COMMUNITIES FOR A BETTER ENVIRONMENT • COUNCILMEMBERS CLAUDIA JIMENEZ, EDUARDO MARTINEZ, AND GAYLE MCLAUGHLIN • EXTINCTION REBELLION SAN FRANCISCO BAY AREA • FRIENDS OF THE EARTH • INTERFAITH CLIMATE ACTION NETWORK OF CONTRA COSTA COUNTY • NATURAL RESOURCES DEFENSE COUNCIL • RODEO CITIZENS ASSOCIATION • SAN FRANCISCO BAYKEEPER • STAND.EARTH • SUNFLOWER ALLIANCE • THE CLIMATE CENTER • 350 CONTRA COSTA COUNTY

April 7, 2022

Re: Appeal of Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project

To the Contra Costa County Board of Supervisors:

BiofuelWatch, California Environmental Justice Alliance, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Extinction Rebellion San Francisco Bay Area, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, Stand.earth, Sunflower Alliance, The Climate Center, and 350 Contra Costa County (Appellants) hereby appeal the Contra Costa County Planning Commission's (Commission) certification of a deficient Final Environmental Impact Report (FEIR) for the Phillips 66 Rodeo Renewed Project (Project). The decision to certify the FEIR violated the requirements of the California Environmental Quality Act (CEQA), and was not supported by the evidence presented. This appeal is based on the arguments set forth in this appeal letter; the comments (Comments) submitted concerning the draft Environmental Impact Report (DEIR) (Attachment A); the attached technical supplement (Attachment B); attached additional supporting information (Attachment C); all associated documents in the administrative record; and arguments and information presented before the Planning Commission at its March 30, 2022 hearing.

As explained below, the FEIR suffers from multiple flaws. First, as described in the comments submitted by NRDC and others (Comments) (identified in the FEIR as Comment 36, or the NRDC comment), the FEIR fails to meet CEQA requirements for disclosure of information on issues critical to assessing these projects; and fails to define and consider appropriate mitigation for significant impacts. The FEIR reflects very few significant substantive changes in response to the Comments. Specific flaws in the FEIR response to the Comments are described in the attached Technical Supplement. Second, the FEIR rejects the comments made by both the Bay Area Air Quality Management District (BAAQMD) and the public calling for the related – and unpermitted – switch to processing soybean oil feedstock at Unit 250 be evaluated as part of the Project. Third, the FEIR does not fully respond to the Comments, as required by CEQA. Fourth, the FEIR presents critical information describing the Project for the first time, which deprives the public of the opportunity to comment on that information. Fifth, neither the FEIR nor the staff report makes necessary findings concerning the evaluated project alternatives. And sixth, the FEIR purports to mitigate impacts but unlawfully postpones development of a mitigation plan until after the conclusion of the CEQA process; which also renders the statement of overriding considerations invalid.

Additionally, Appellants have identified changes that need to be made to ensure that the approval conditions pertaining to site cleanup are viable and effective. We support those cleanup conditions in principle, but have described in this appeal the need to adjust the currently very protracted timeline, and to regularly re-evaluate the proposed financial guarantee to ensure that it is sufficiently robust to cover the costly soil remediation of the Project site, where highly polluting refinery operations have been occurring for over a century.

For these reasons, Appellants request that the Board of Supervisors grant this appeal, reject certification of the FEIR, and instruct the Department of Conservation and Development (Department) and Commission to develop a revised DEIR that meets the requirements of CEQA be prepared and circulated for public comment.

To be clear, this appeal is not presented as a referendum on the merits of the Project. CEQA is a tool to aid government in making decisions about whether a project will have significant impacts; and, if so, whether those impacts have been mitigated as necessary. As of now, that tool is not being used properly under the law. The proposed Project at issue here is unprecedented in scope, and proposes a refining technology – hydrotreating esters and fatty acids (HEFA) – that is newly emerging in California on a large scale. A determination whether large-scale deployment of HEFA technology is an appropriate or feasible path for California, and whether its purported benefits outweigh its impacts, cannot be responsibly made without the thorough vetting of all relevant impacts that CEQA requires. We ask that the Board of Supervisors step in to ensure that review takes place.

I. The Decision to Certify the FEIR is Contrary to Law and Not Supported by Substantial Evidence

The Comments documented numerous and basic ways in which the DEIR failed to meet CEQA's requirements for disclosure and development of mitigation. Nothing provided in the Response or the FEIR adequately explains, excuses, or addresses that failure.

The following is a summary of some key issues left unaddressed in any meaningful way by the FEIR and Response:

- *Failure to provide an adequate project description.* Fundamental to CEQA is the requirement that a project be described in sufficient detail to permit informed decisionmaking. "An accurate, stable and finite project description is the *síne qua non* of an informative and legally sufficient EIR." *San Joaquin Raptor/Wildlífe 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). The DEIR provided essentially no information about the technology proposed to be deployed in the Project – which technology, as described elsewhere in the Comments, is being proposed at an unprecedented scale in the two Bay Area refinery conversions, and has the potential for numerous harmful direct and indirect environmental impacts. The Response provides only partial information, insufficient to satisfy CEQA. In particular, the Response failed to adequately address information in the Comment identifying an undisclosed debottlenecking impact of the Project that would increase its impacts.[1] Comment at 11-14. (Although the Response provides additional information, as noted below, its late disclosure forecloses effective public comment on it.)

- *Improper baseline.* The baseline from which the FEIR calculates impacts is continued operation of the Phillips 66 Rodeo refinery (Refinery) at historic levels of production. As explained in the Comment, this baseline is not consistent with available facts, which demonstrate severe and increasing constraints on the Refinery's access to crude feedstock. Comment at 14-24. As explained in the attached Technical Supplement, the response in the FEIR falls short of addressing this concern.[2] The inaccurate baseline skews all other analysis in the FEIR. If the baseline or "no project" scenario is diminished throughput at the Refinery, then the purported decreases in impacts from crude oil refining have not been assessed accurately.

- *Failure to account for potentially increased operational upsets.* Commenters presented extensive evidence – supported by both their technical consultant and peer-reviewed analysis – that HEFA biofuel processing can lead to increased process upsets as a result of, among other things, higher processing temperatures and gumming and fouling of refinery equipment that results from repurposing crude oil refining equipment to run lipid feedstocks. These upsets can cause worker and public hazards and increased flaring. Comments at 37-42. As explained in the Technical Supplement, the FEIR did not fully address these additional risks.[3] We note as well that notwithstanding the FEIR's emphasis on existing regulation, the FEIR does not attach a flare minimization plan (per BAAQMD regulation 12-12-404.2). The inadequacy of the Response concerning operational upsets is further described in the attached technical supplement.

- *Failure to account for the impact of massive food system oil consumption.* The Project would consume on a colossal scale, unprecedented in California, oils that are either directly used as food products (soybean oil) or indirectly used in the food system (corn oil used in animal feed). Commenters extensively documented – based on peer-reviewed science - the environmental impacts risks from this massive disruption in the food system, including and especially the risk that soybean oil demand and associated price spikes (which are already happening as a result of existing biofuel projects) will incentivize production of palm oil and associated deforestation. Comments at 24-37. Nothing in the Response refutes these facts or the cited scientific sources. Commenters presented available information from which the

[1] Catalytic reforming units retained in the project to process gasoline blend stocks coproduce hydrogen (FEIR at 3-44, 4-3, DEIR at Table 3-3) yet the resultant biofuel processing impacts are not disclosed in the EIR. See Technical Supplement by Greg Karras (Attachment B) Section 2.
[2] *Id.* Section 1.
[3] *Id.* Section 4.

County could readily have grounded estimates of likely volumes of feedstocks the Project will consume, but the FEIS offers only a conclusory dismissal of feedstock estimation as "speculative." FEIR at 3-32.

- *Improper deferment of odor mitigation plan.* The FEIR continues to unlawfully delay addressing potential odors from the project – whose impacts may be considerable depending on what feedstocks are used. CEQA plainly prohibits deferring development of mitigation until after the CEQA process is complete – the point of CEQA is to disclose and allow the public to vet essential mitigation measures. "Formulation of mitigation measures shall not be deferred until some future time." CEQA Guidelines § 15126.4(a)(1)(B). Yet despite changes made to proposed Mitigation Measure AQ-2, the County continues to propose that the measure be developed after the completion of the CEQA process, completed only "prior to operation of the Project." Response at 3-73. This approach is unlawful and must be corrected.

- *Failure to account for cumulative impacts.* As pointed out in the Comments, the County ignored the elephant in the room when evaluating cumulative impacts. Focused on comparisons to geographically proximate but mostly unrelated projects, it failed to account meaningfully for the fact that the Project is happening in tandem with the nearby Marathon renewable fuels project. These two projects together (added to the dozens of smaller listed projects already in operation or planned) would result in a massive disruption of food crop markets, with resultant land use consequences. Comments at 72-85. The Response fails to address these issues at all, save repeated assertions that addressing cumulative feedstock impacts would be "speculative." Response at 3-25 - 26. Furthermore, since filing the Comments, experts have additionally indicated the cumulative impacts of projects like the Martinez Project and Phillips 66 Rodeo Renewed Project bear a great risk of causing tens of thousands of hectares of deforestation—thus negating any potential climate benefit asserted.[4]

- *Inconsistency with California climate pathways.* The Comments presented detailed analysis, backed up by studies developed for CARB and other state agencies, that the volume of biofuels the Project would produce – particularly in combination with the Rodeo Renewed project – would represent an oversupply of renewable diesel that exceeds the supply anticipated in analysis of California's climate pathways. In particular, the Comments identified in depth a risk that the heightened production of renewable diesel contemplated by the Project could actually cause a net increase in greenhouse gas emissions by increasing exports of petroleum distillates. Comments Appendix C Section 2. As explained in the Technical Supplement, the emission shifting analysis was largely ignored in the Response.[5]

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[4] C. Malins and C. Sandford, Animal, vegetable or mineral (oil)? Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States. Cerulogy, ed. International Council on Clean Transportation, Jan. 2022. https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf (Attachment C).

[5] Technical Supplement Section 3.

- *Failure to adequately mitigate transportation risk impacts.* The Comments provided detailed concerns with regard to marine impacts, concerns which were dismissed by the County under the assumption that non-petroleum feedstocks will react to cleanup methodologies identically to petroleum. FEIR 3-605 (Responses 160, 162), 3-608 (Responses 171, 172), 3-611 (Response 183), 3-613 (Response 187). No support is offered for the assumption that petroleum and non-petroleum **feedstocks** react similarly in marine environments, nor is there any evidence offered that current assets will respond to spills of non-petroleum feedstocks. To put it plainly, there is no guarantee that a large spill of vegetable oil will even be responded to, let alone cleaned up effectively, and there is no analysis of what such a cleanup would entail or the damage such a spill could cause. This impact is recognized as significant and unavoidable, but common-sense mitigation such as committing to response and cleanup of spills of non-petroleum feedstocks at every point along their transportation pathways is not included in the FEIR.

This list is not a complete catalogue of all of the deficiencies of the FEIR. It is merely intended to illustrate that enormously important issues raised by Commenters remain unaddressed in the FEIR. The County's overall response to the issues raised by Commenters has been to offer justifications (where it responds to the comments at all) but not remedy. The County made very few changes to the FEIR in response to the Comments; and where it did make changes (for instance, regarding the odor mitigation measure), it did not fix the problem. This appeal should be granted with orders to the Department and Commission to fully address the issues raised by Commenters, including development of mitigation as necessary.

II. The FEIR Improperly Rejected the Direction of BAAQMD, and the Request of Commenters, to Include Modified Unit 250 in the Project Analysis.

The Comments explained that diesel hydrotreater Unit 250 at the Refinery has been recently converted from petroleum distillate to soybean oil processing without a Clean Air Act permit; and pointed out that this conversion should have been included as part of the Project for purposes of CEQA review. Comment at 5. BAAQMD, which is currently investigating the unpermitted conversion, agreed in its comment on the DEIR, asking that the County "please include Unit 250's throughput of 12,000 bpd of renewable fuel in the Project's emission calculations" unless it can provide documentation that BAAQMD permits issued to Phillips 66 include that unit. FEIR at 3-69. The Response references the fact that Title V operating permit includes Unit 250 – but BAAQMD's investigation documents make clear that the question pertains to whether the permit documents include Unit 250 as a renewable feedstock processing unit, not simply whether the unit itself is referenced in the permit. Accordingly, the DEIR should be recirculated with the Unit 250 emissions included as part of the Project.

III. The FEIR Fails to Comply with the CEQA Requirement to Respond to Public Comments

A key component of CEQA analysis is a considered and thorough response to public comments raising significant environmental issues, where appropriate making changes to the EIR based on them. CEQA Guidelines § 15008. CEQA sets a high bar for the substance of responses, which must fully address each question raised. In particular, the major environmental issues raised when the lead agency's position is at variance with recommendations and objections raised in the comments must be addressed in detail giving reasons why specific comments and suggestions were not accepted. There must be good faith, reasoned analysis in response. Conclusory statements unsupported by factual information will not suffice. The level of detail contained in the response, however, may correspond to the level of detail provided in the comment (i.e., responses to general comments may be general).Id. at 15008(c).

That bar has not been met here. As detailed in the Technical Supplement, the Response fails to address a number of key issues raised in the Comments. These include, most notably, questions pertaining to the "emission shifting" impact of the Project affecting the greenhouse gas emissions analysis, and potential debottlenecking impact of certain Project components.

IV. The County Has Made No Findings Concerning Choice of Alternatives and Throughput Volumes

The FEIR evaluates three alternatives in addition to the no project alternative: a terminal-only alternative, a no temporary increase in crude oil alternative, and the reduced feedstock alternative, with the latter identified as the "environmentally superior" alternative. Yet nowhere in either the FEIR or the staff report does the Department identify which is the preferred alternative, and support that finding with facts and documentation. There is simply no finding at all, much less a finding supported by substantial evidence.

Compounding the problem is that the conditions of approval nowhere specify a limit on production rates. The staff report specifies that "up to 80,000 barrels per day" of feedstock "could arrive" at the Refinery (staff report at 7); but nothing in the approval conditions limits throughput – and attendant impacts – to that amount. Similarly, the EIR analyzed biofuel production and shipping of 67,000 barrels per day;[6] yet nothing in the conditions limits the refinery to that amount. Additionally, it analyzed "temporary" project impacts from refining 105,000 barrels per day of crude and gas oil;[7] but again, nothing constrains the Project from processing more feedstock than that. This is a fatal flaw in the CEQA process. Nothing constrains the Project from processing at a larger rate, with larger impacts, than what was analyzed.

Given these foundational failures to comply with CEQA, the FEIR and approval conditions as presented should be rejected, with orders that the Department make findings among

[6] See FEIR at 4.2, Revised Table ES-1.
[7] See FEIR at 4-3, Revised Table ES-2.

the alternatives evaluated based upon evidence in the record; and that its finding regarding throughput volume be reflected in a condition of approval governing throughput.

V. New Information Describing the Project Provided in the Response Must be Re-Circulated to Allow for Public Comment

On several topics, the Response provides for the first time information describing the Project and its key potential impacts. This is most notably true with respect to public safety risks associated with repurposing crude oil processing equipment for processing renewable diesel feedstocks. As explained in the Technical Supplement, the FEIR responds to commenters' concerns with dozens of new assertions and 18 newly-identified technical references.

This disclosure constitutes essential information that the public as a whole (not just Commenters via their consultant) should have had disclosed to them in the DEIR. It is not sufficient, for purposes of CEQA, to present critical information describing a key potential impact only in the FEIR, when opportunity for meaningful public comment has passed. For this reason, the DEIR should be revised to include any information newly disclosed in the FEIR and Response, and ordered recirculated in response to this appeal.

VI. The Statement of Overriding Considerations is Inadequate

The law is clear that, while a government body may choose to override significant impacts that cannot be feasibly mitigated, it may not use a statement of overriding considerations as a basis for project approval in place of feasible mitigation measures. *City of Marina v. Board of Trustees of California State University* (2006) 39 Cal.4th 341, 368, citing Public Resources Code § 21081 ("A statement of overriding considerations is required, and offers a proper basis for approving a project despite the existence of unmitigated environmental effects, only when the measures necessary to mitigate or avoid those effects have properly been found to be infeasible. . . . CEQA does not authorize an agency to proceed with a project that will have significant, unmitigated effects on the environment, based simply on a weighing of those effects against the project's benefits, unless the measures necessary to mitigate those effects are truly infeasible.").

Here, the FEIR fails to even identify and address significant categories of impacts, much less mitigate them. And as noted above, FEIR and staff report did not specifically address the alternative of reduced throughput, and the feasibility of reducing impacts in that manner. Additionally, the mitigation proposed for odors, as described above, is inadequate and unlawful, because it is not being fully defined until after the conclusion of the CEQA process. For this reason alone, the Statement of Overriding Considerations presented by staff is legally inadequate to support approval of the Project.

VII. The Provisions Regarding Site Cleanup Need to be Strengthened to Ensure Effectiveness

We support in principle the County's inclusion of a requirement in the Conditions of Approval that the Project applicant "investigate soil conditions at the site and, where necessary, clean-up [sic] and restore the site to a condition suitable for commercial and industrial land uses." Staff report at 18. As discussed in the Comment, the Refinery is almost certainly heavily contaminated, having been home to refining operations since before the turn of the 20th Century. Comments at 88-90. However, Appellants appeal the condition as written, as there are several ways in which it must be strengthened in order to ensure effective implementation.

First, the timeline on which Phillips 66 is allowed to conduct the soil investigation and remove unused equipment is excessively long and unsupported by evidence. There is no reason it should take 15 years to complete it (staff report at 20) – indeed, there is no guarantee the Project will still be operating at that time; or that, in a rapidly changing energy economy, Phillips 66 will remain a functioning economic entity. The County should determine a reasonable timeline for completing this investigation based on usual industry practice. Similarly, there is no explanation or evidence provided to support giving Phillips 66 20 years to remove portions of the Refinery that will not be used for the Project. There is no reason not to require such removal concurrent with, or immediately following, completion of the Project. Additionally, the soil investigation should be completed after such removal, to address any contamination that may be either inaccessible while the unused equipment remains on the site, or caused by the process of removal.

Additionally in this regard, we note that the condition does not expressly specify that the work plan include, or be amended following completion of the soil investigation to include, remediation of soil contamination – it references only timelines for demolishing and removing equipment. Staff report at 19. That deficiency needs to be rectified as well.

Second, the corporate financial guarantee requirements need to be amended to ensure that the cleanup will be paid for. In the current version, there is no requirement that the corporate guarantee be adjusted upon completion of the soil remediation study – which will determine in substantial part the cost of the cleanup. Although the corporate guarantee is required to be updated within 30 days of any work plan amendment (staff report at 22), there is no requirement, as noted, that the work plan be amended upon completion of the soil investigation. Hence, the actual – and almost certainly large – costs of soil remediation will not be factored into calculation of the corporate guarantee.

Third, the County should revisit the corporate guarantee annually, to ensure that economic circumstances and corporate financial health have not diminished the validity of the guarantee. The oil industry is volatile and changing as the national and state economies shift toward renewable energy, making it important that that guarantee be subject to continuing reassessment of its viability. The County should require external security (insurance or letters of credit) upon any sign of diminished strength of the corporate guarantee.

Finally, the County should reconsider its limitation of cleanup levels to "commercial and industrial uses." Prior to the soil investigation, it cannot be known the level of cleanup that is possible at the Refinery. The County should set the cleanup level so as to provide the Rodeo community with the broadest possible latitude in repurposing the Refinery site.

VIII. Conclusion

Recirculation of a draft EIR is required when the draft was "so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded," CEQA Guidelines § 15088.5(a)(4), a standard that is met here. For the reasons stated above, Appellants respectfully request that the Board of Supervisors grant this appeal, reject the certification of the FEIR and approval of the Project, and remand to the Department and the Commission with orders that the DEIR be revised and recirculated so as to comply fully with CEQA; and that they address through thorough disclosure and analysis all issues raised in the Comments and this Appeal.

Respectfully submitted,

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ATTACHMENT A

Comments Concerning DEIR

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 §

[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

[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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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 *síne 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. <u>The DEIR Failed to Disclose Two Project Components Undertaken Separately From the Project Permitting Process</u>

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.

[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

[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. <u>The DEIR Fails to Disclose Information Regarding the HEFA Biofuel Refining Process Essential to Evaluating its Impacts</u>

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

[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. <u>The DEIR Fails to Disclose a Project Component Designed to Debottleneck Hydrogen-limited Onsite Refining Capacity</u>

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

[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. <u>Inherent Infrastructure Constraints Limit Crude Feedstock Availability to the SF Complex</u>

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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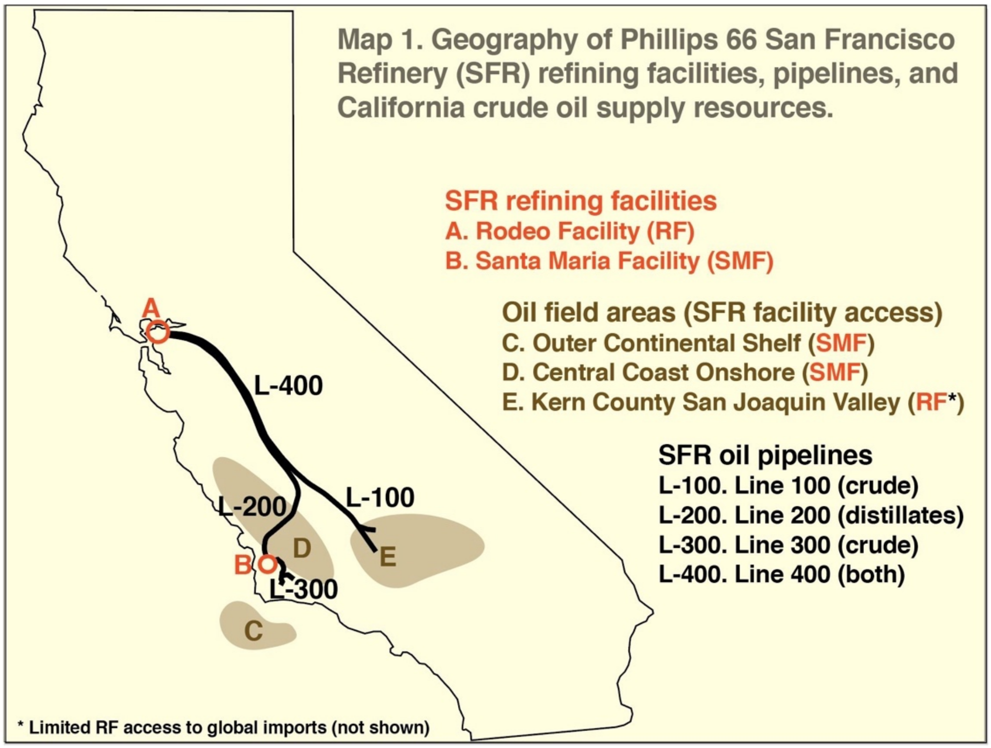
[41] The increase would be from the current marine terminal input limit of 51,182 barrels per day (b/d) limit now to 125,000 b/d.
[42] Application at 12.
[43] *Id.* at 11-12 (listing Project components).
[44] Map 1 is only approximately to scale, consistent with facility and pipeline maps in the DEIR, 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

[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.

[52] Karras, 2021c. Careful review of DEIR Figure 3-5 confirms this accurate description of pipeline flows, once the reader knows that crude <u>does not</u> 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.

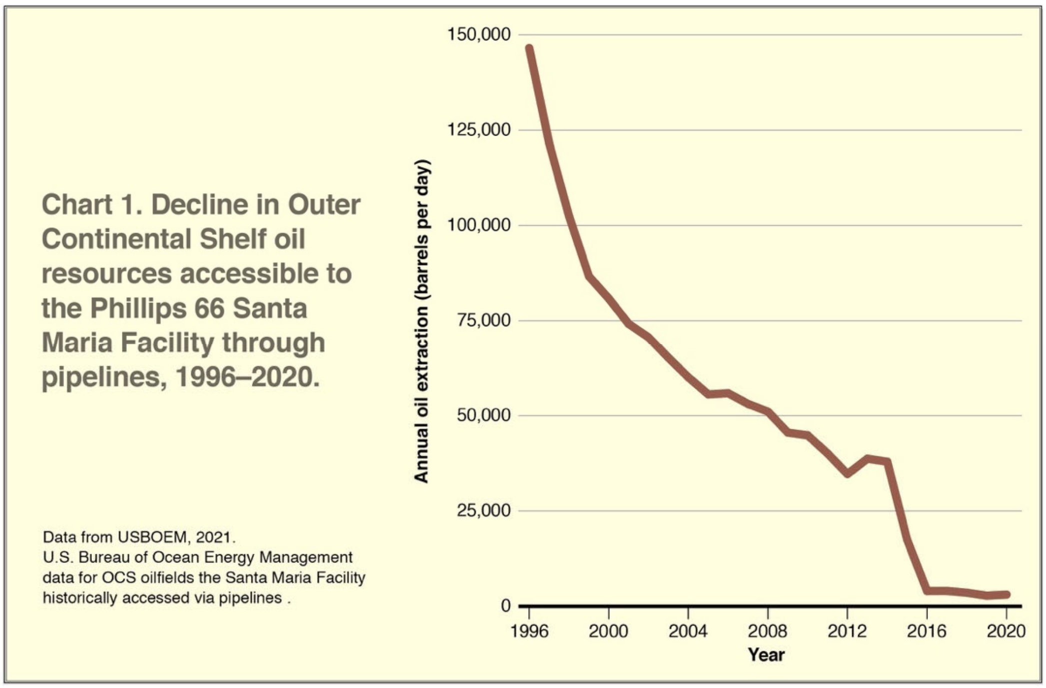

Chart 1. Decline in Outer Continental Shelf oil resources accessible to the Phillips 66 Santa Maria Facility through pipelines, 1996–2020.

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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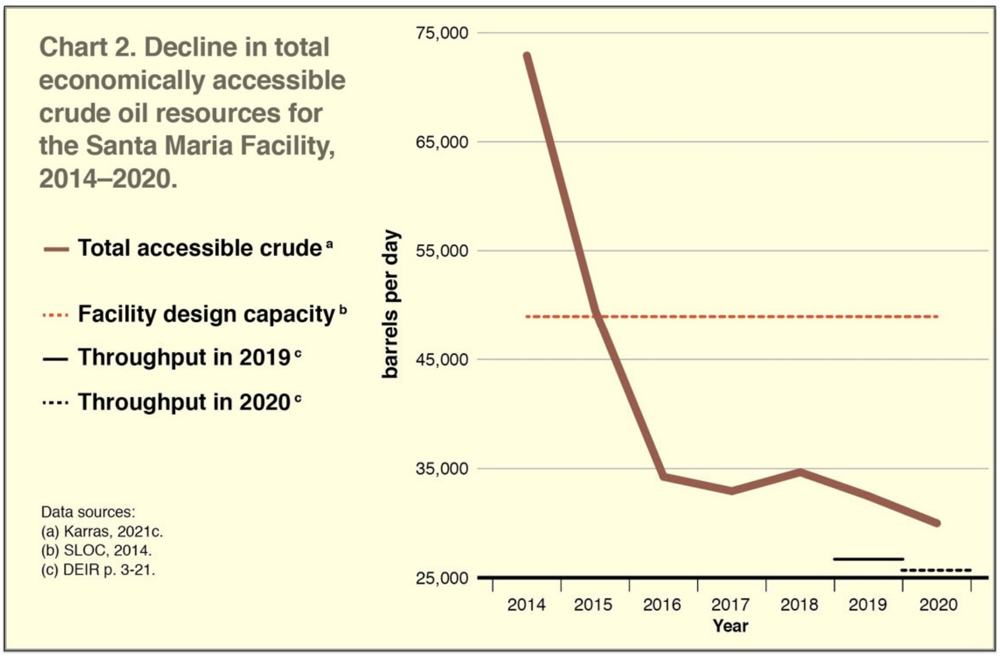
[64] SLOC, 2014.
[65] USBOEM, 2021a. U.S. Bureau of Ocean Energy Management. *Pacific Production;* data tables for the Pacific OCS Region, 1996–2021. https://www.data.boem.gov/Main/PacificProduction.aspx#ascii
[66] USBOEM, 2021b. U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement/Bureau 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

[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

[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

[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

[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

[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

[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).

[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. <u>GHG Emissions Impacts Vary With Different Potential Feedstocks</u>

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

[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

[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:

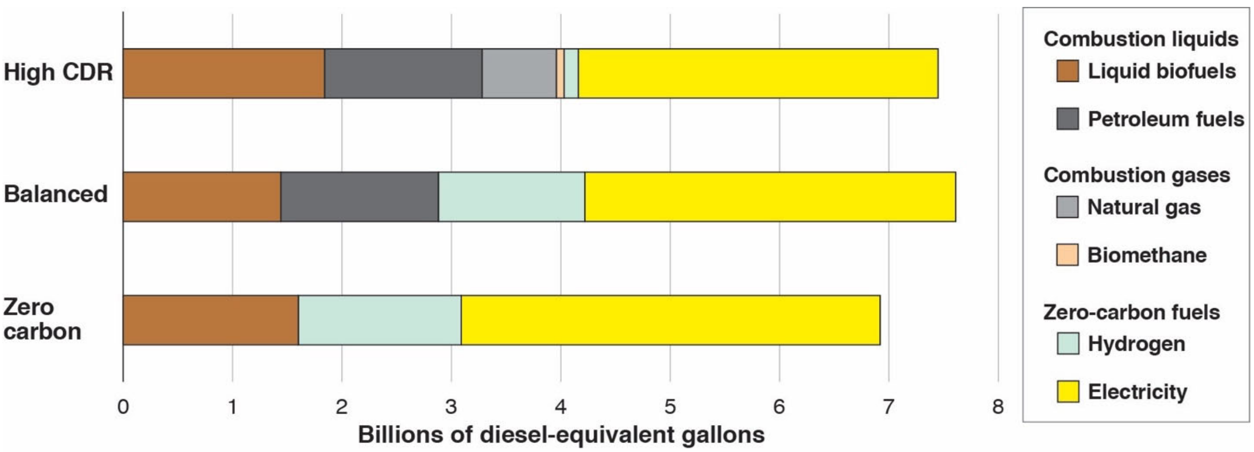

Chart 3: California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.
Adapted from Figure 8 in Mahone et al. (2020).[200] Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion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

[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. <u>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</u>.

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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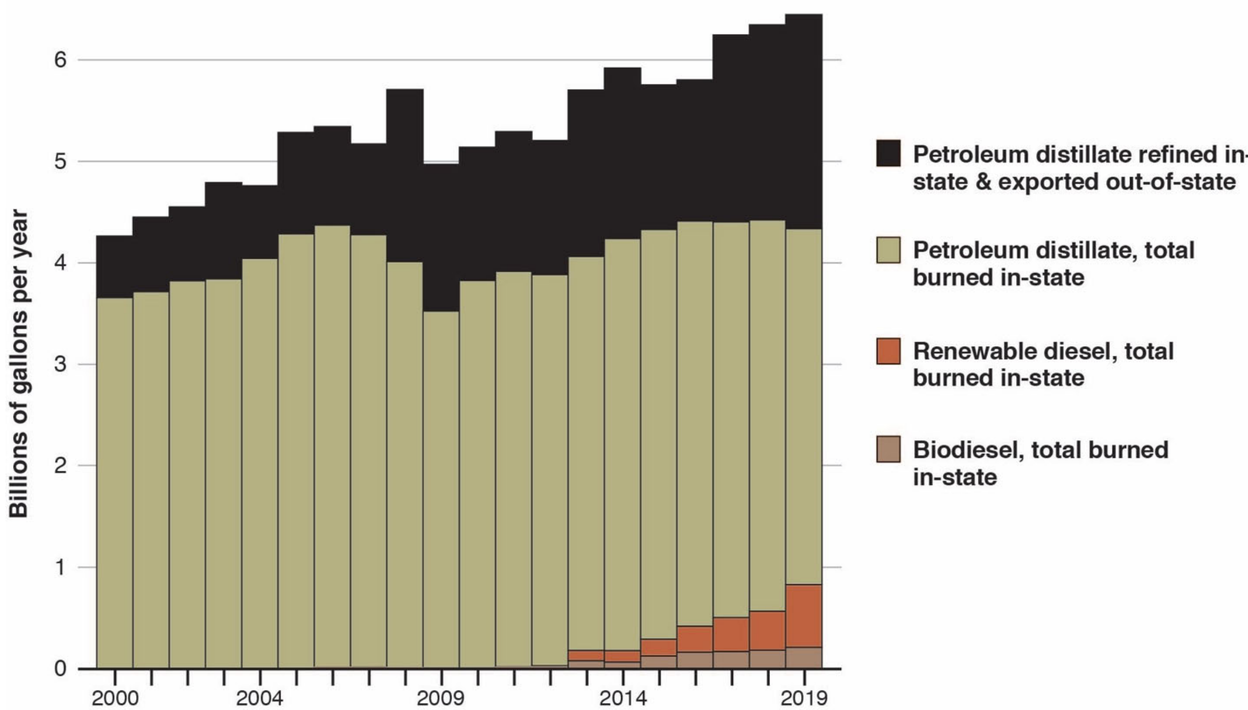
[211] "Project operations would decrease emissions of GHGs that could contribute to global climate change" (DEIR p. 2-5) including "indirect emissions" (DEIR p. 4.8-258) and "emissions from transportation fuels" (DEIR p. 4.8-266).
[212] CCR §§ 38505 (j), 38562 (b) (8).
[213] CEC, Fuel Watch data.
[214] 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. <u>The DEIR Fails to Consider Exports in Evaluating the Project's Climate Impact</u>

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

[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.

[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

[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

[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

[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]

[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

[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

[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

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

Data from 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.

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

Data 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.

Month	Capacity Utilized **in 2021**	Pre-COVID range for same month in 2010–2019		
		Minimum	Median	Maximum
January	73.3 %	76.4 %	83.7 %	90.1 %
February	74.2 %	78.2 %	82.6 %	90.9 %
March	81.2 %	76.9 %	84.8 %	95.7 %
April	82.6 %	77.5 %	82.7 %	91.3 %
May	84.2 %	76.1 %	84.0 %	87.5 %
June	88.3 %	84.3 %	87.2 %	98.4 %
July	85.9 %	83.3 %	90.7 %	97.2 %
August	87.8 %	79.6 %	90.2 %	98.3 %
September	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. <u>The DEIR Failed to Consider ZEH as Mitigation for Significant Project Impacts</u>

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. <u>The DEIR Ignored a Critical Fact Supporting the Scalability of ZEH</u>

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

[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

[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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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).

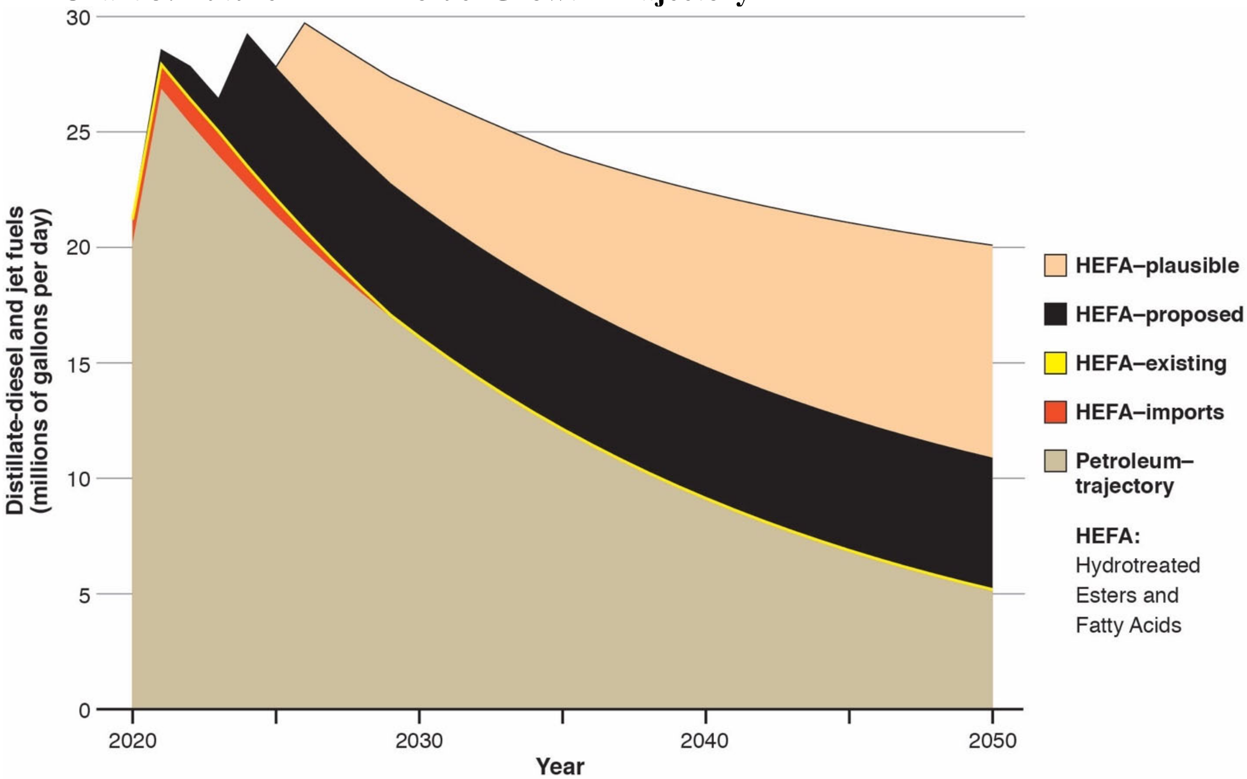
Chart 5 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile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

[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]

[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

[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

[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.

[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

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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.

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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 How HEFA works

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 HEFA feedstocks

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

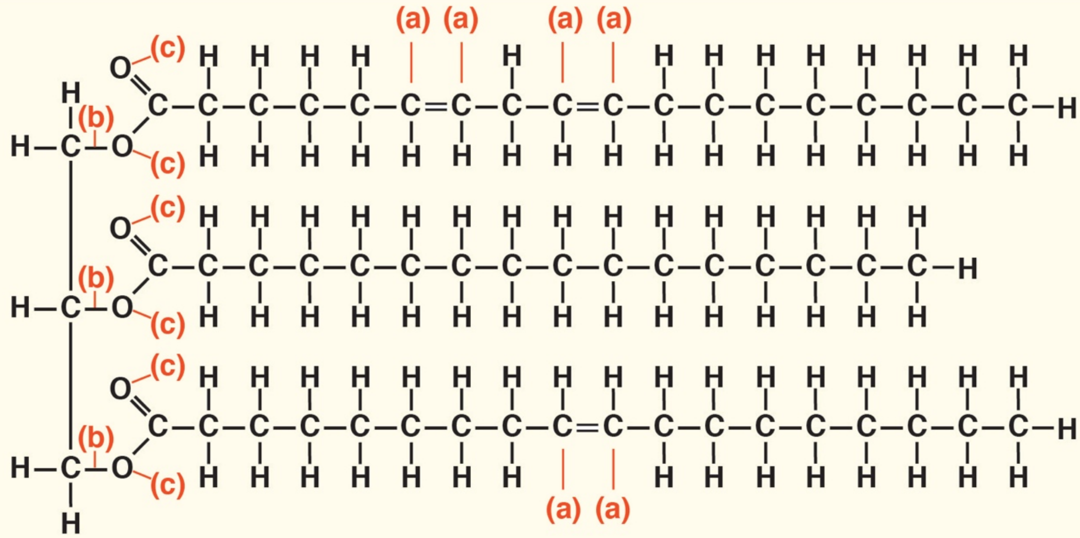
All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).[2 3 4 6] "Hydrotreating" signifies a hydro-conversion 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.



Triacylglycerol Components
C: carbon
O: oxygen
H: hydrogen

Chemical Bonds
— Single Bond
= Double Bond

HEFA Reaction Sites
(a) Saturation
(b) Depropanation
(c) Deoxygenation

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)	U.S. (%)	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 (MM t/y) [c]	Percentage of U.S. and California supplies for all uses: 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.

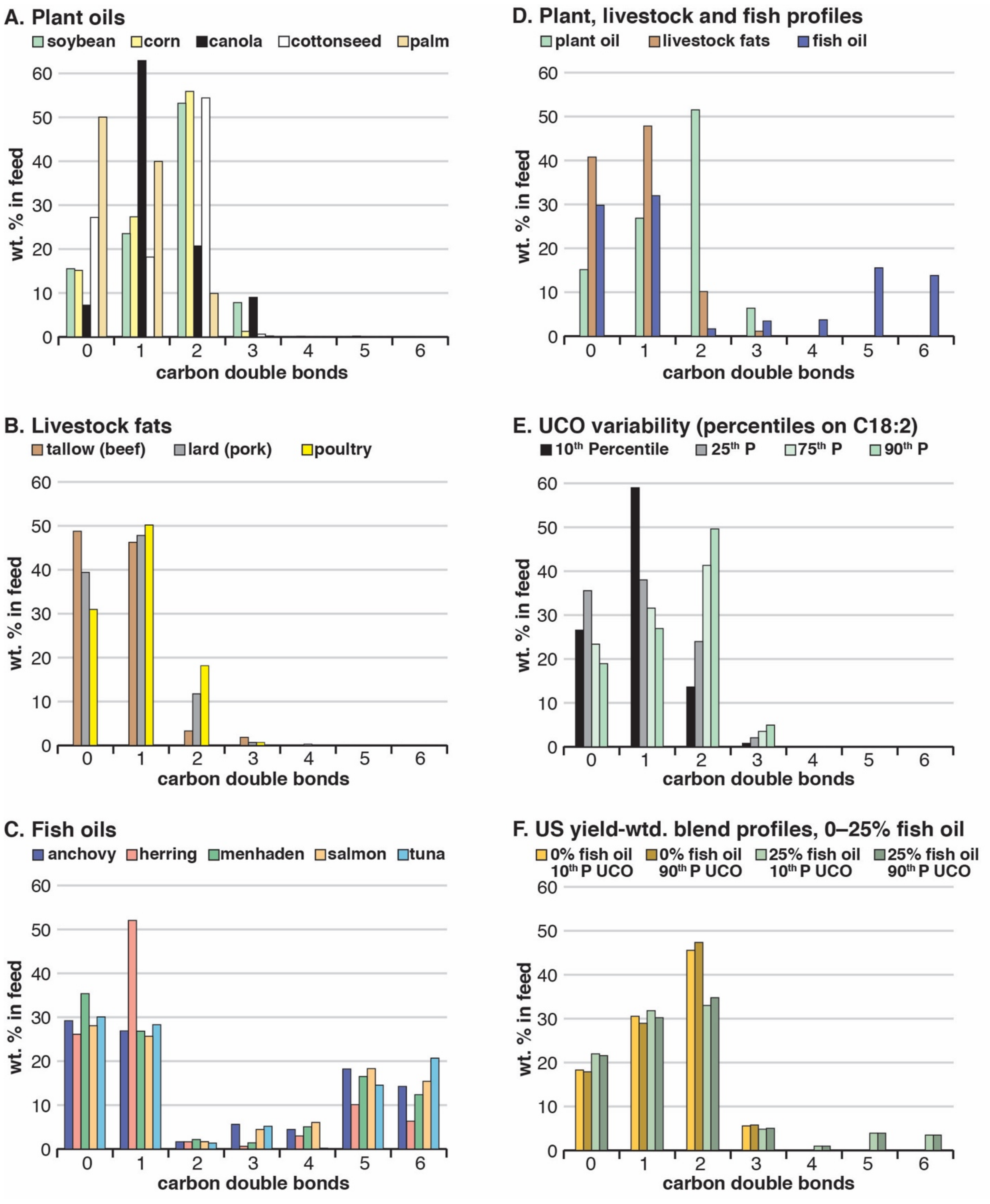
In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock 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.

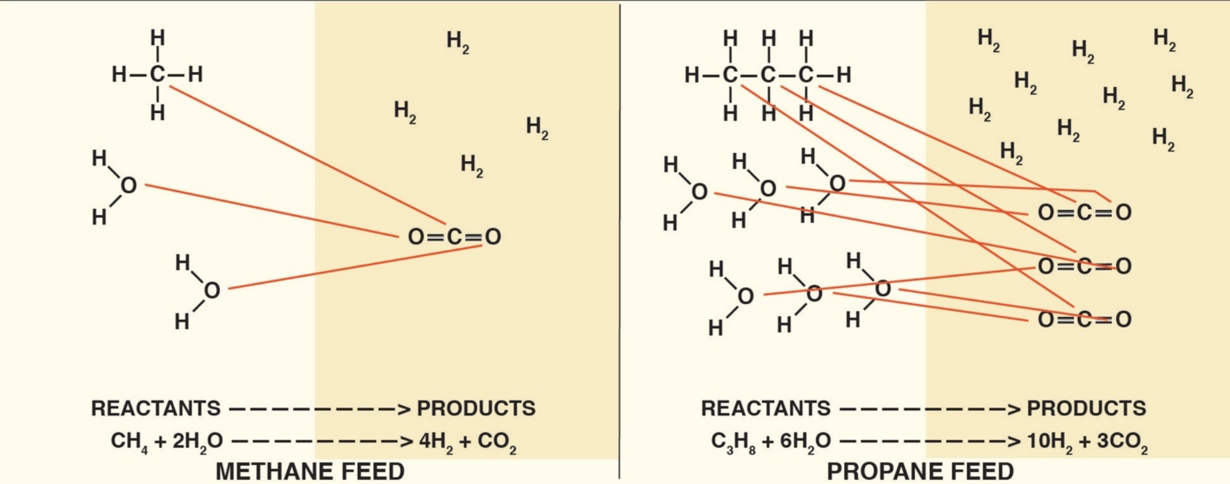


Diagram 2. Hydrogen steam reforming: reforming and shift reactions.
As the reforming and shift reactions produce hydrogen (H_2) from the hydrogen atoms (H) in hydrocarbons and steam, they bond the left-over carbon (C) and oxygen (O) atoms in those reactants together to form carbon dioxide (CO_2). This 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 hydro-conversion 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] Lower bound	Upper bound	Carbon intensity (kg/b)	Mass emission[c] (Mt/y)
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]

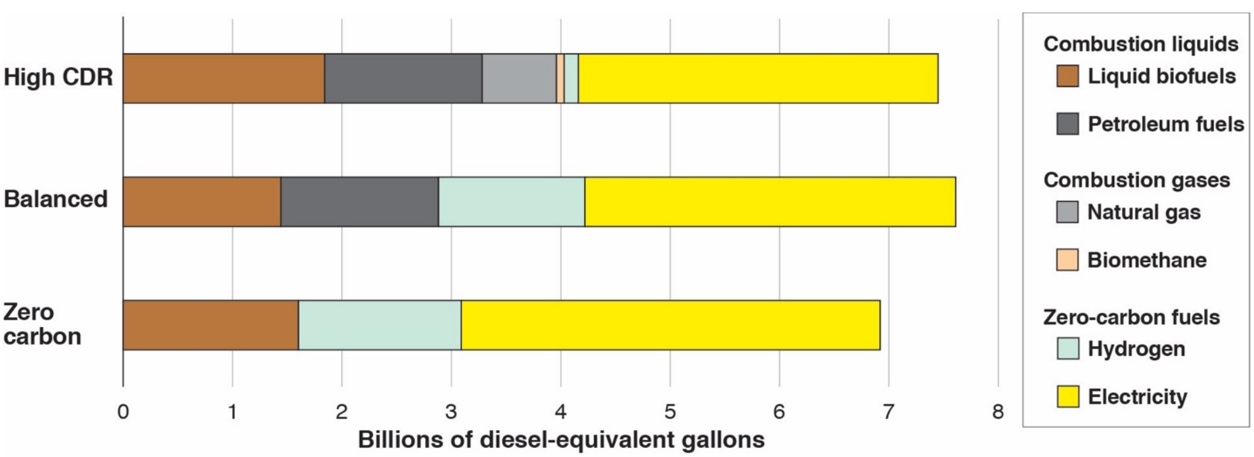
Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by 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]

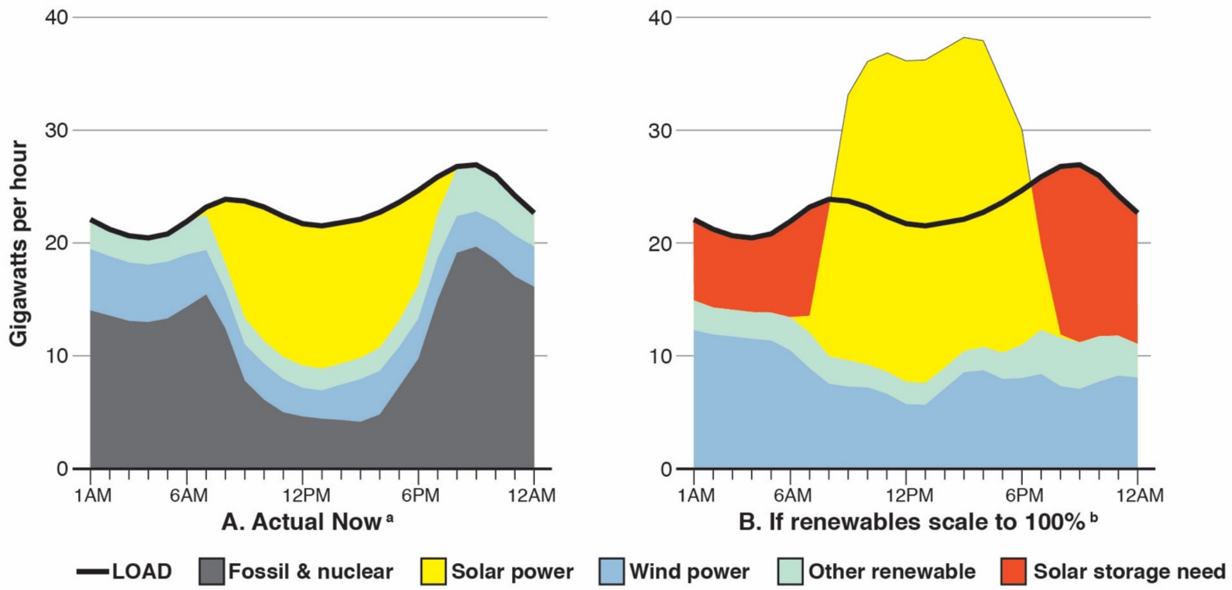
Renewable-powered electrolysis for future solar and wind power growth

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

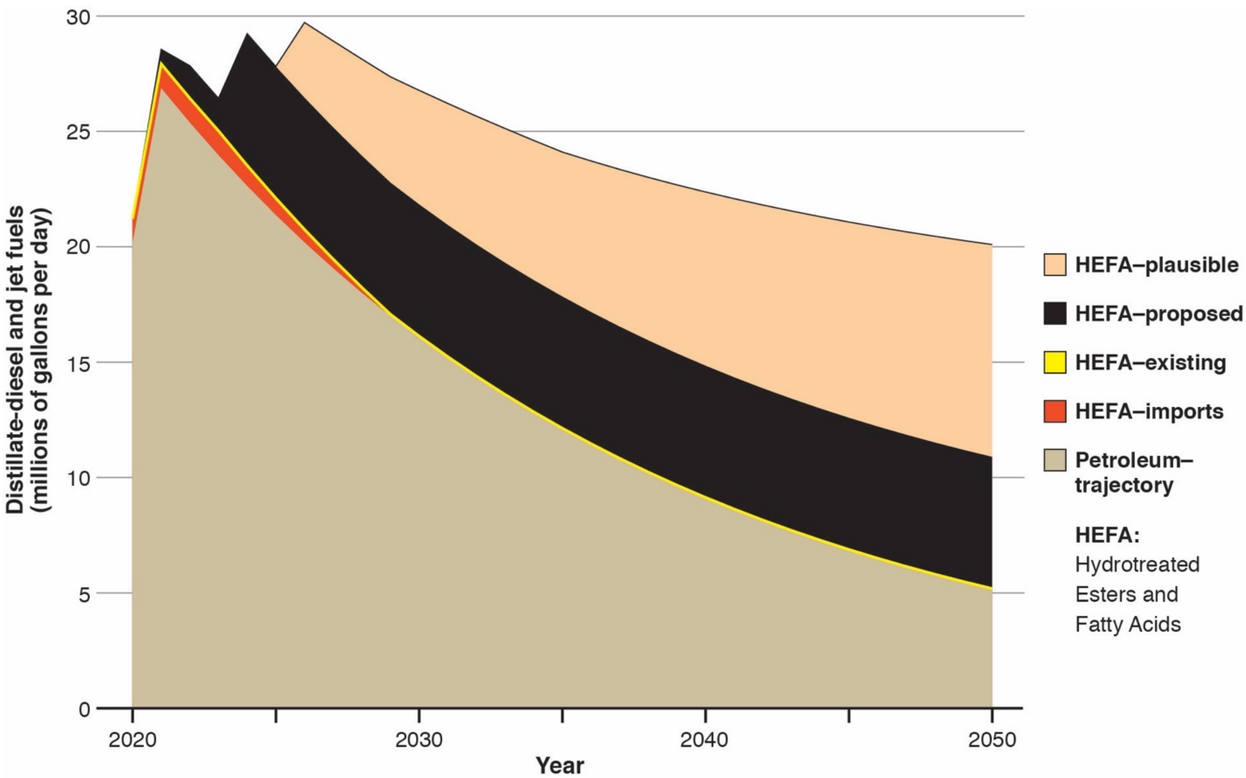
Proposed projects would exceed HEFA biofuel caps

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 <u>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</u>

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.

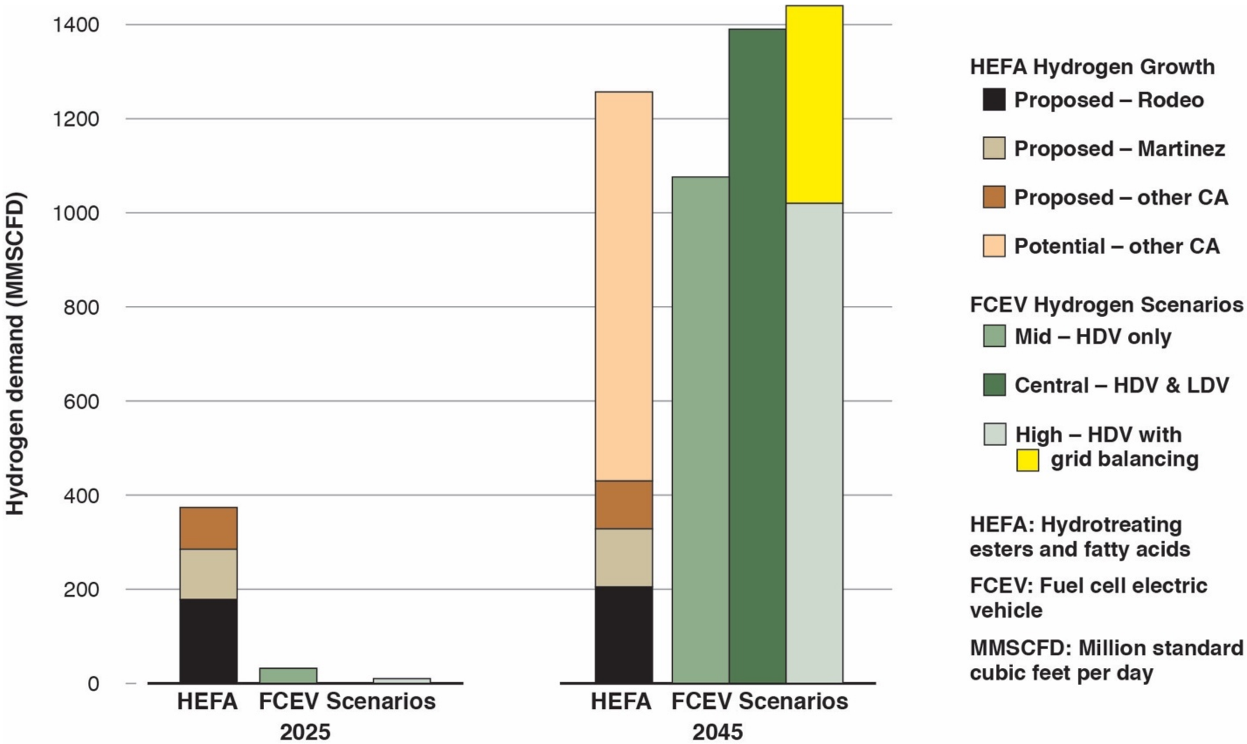
Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

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 <u>Electrolysis would prevent HEFA biofuels from increasing the carbon intensity of hydrocarbon fuels refining</u>

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 <u>Three potential HEFA jet fuel processing strategies</u>

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. <u>*See*</u> 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 (<u>*see*</u> 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 <u>CO_2 co-production and emission from hydrogen production by steam reforming</u>

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 <u>Feedstock effects on CI resulting from Isom-IHC hydrogen demand</u>

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).

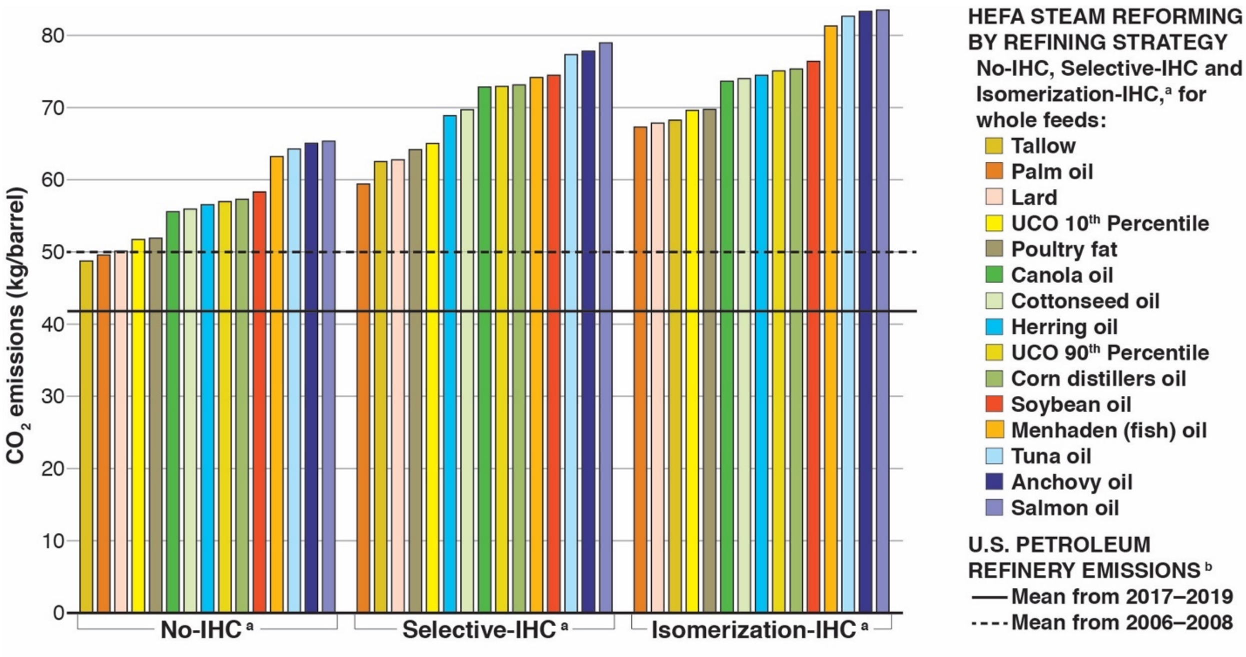
3.5 <u>Comparison with petroleum refining CI by feedstock and processing strategy</u>

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. <u>See</u> Illustration 1.

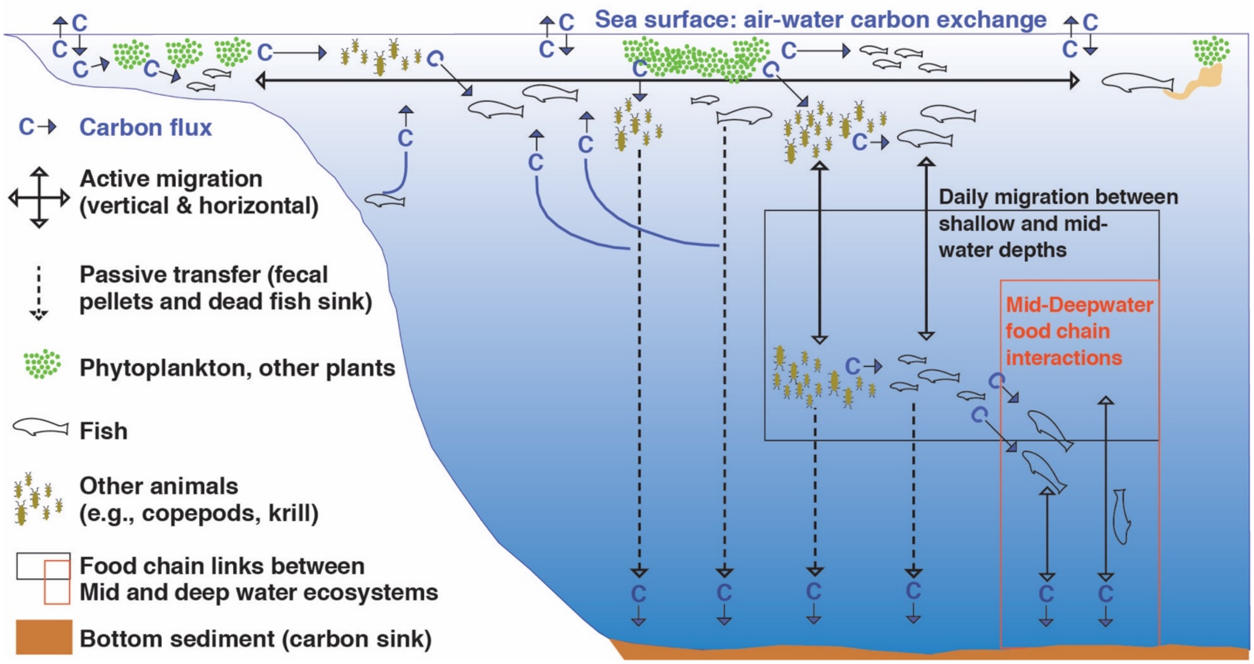


Illustration 1. Biological pump to the deep oceans carbon sink

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. <u>*See*</u> 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 Feed-stock Supply	U.S. (MM t/y)	World (MM t/y)	Supply / Demand (%) U.S.	World	Supply / Demand (%) U.S.	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 <u>Priorities for future work</u>

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				Oxygen	Carbon	FA-specific hydrogen inputs	
			Density	content	double	Deoxygenation[c]	Saturation[d, e]
common name	Shorthand	Formula[b]	(kg/b)*	(wt. %)*	bonds	(kg H_2/b)	(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

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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-γ-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.

[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

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

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

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

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

1.1.3 Potential project hydrogen production technologies.

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

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

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

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

1.2 Process Chemistry and Reaction Conditions

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

1.2.1 Key differences in processing compared with petroleum refining

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

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

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

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

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

1.2.2 Relationships between feedstock choices, product targets and hydrogen inputs

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

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

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

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

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

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

1.2.3 Changes in process conditions of repurposed equipment

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

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

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

1.3 Process Inputs

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

1.3.1 Change and variability in feedstock chemistry and processing characteristics

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

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

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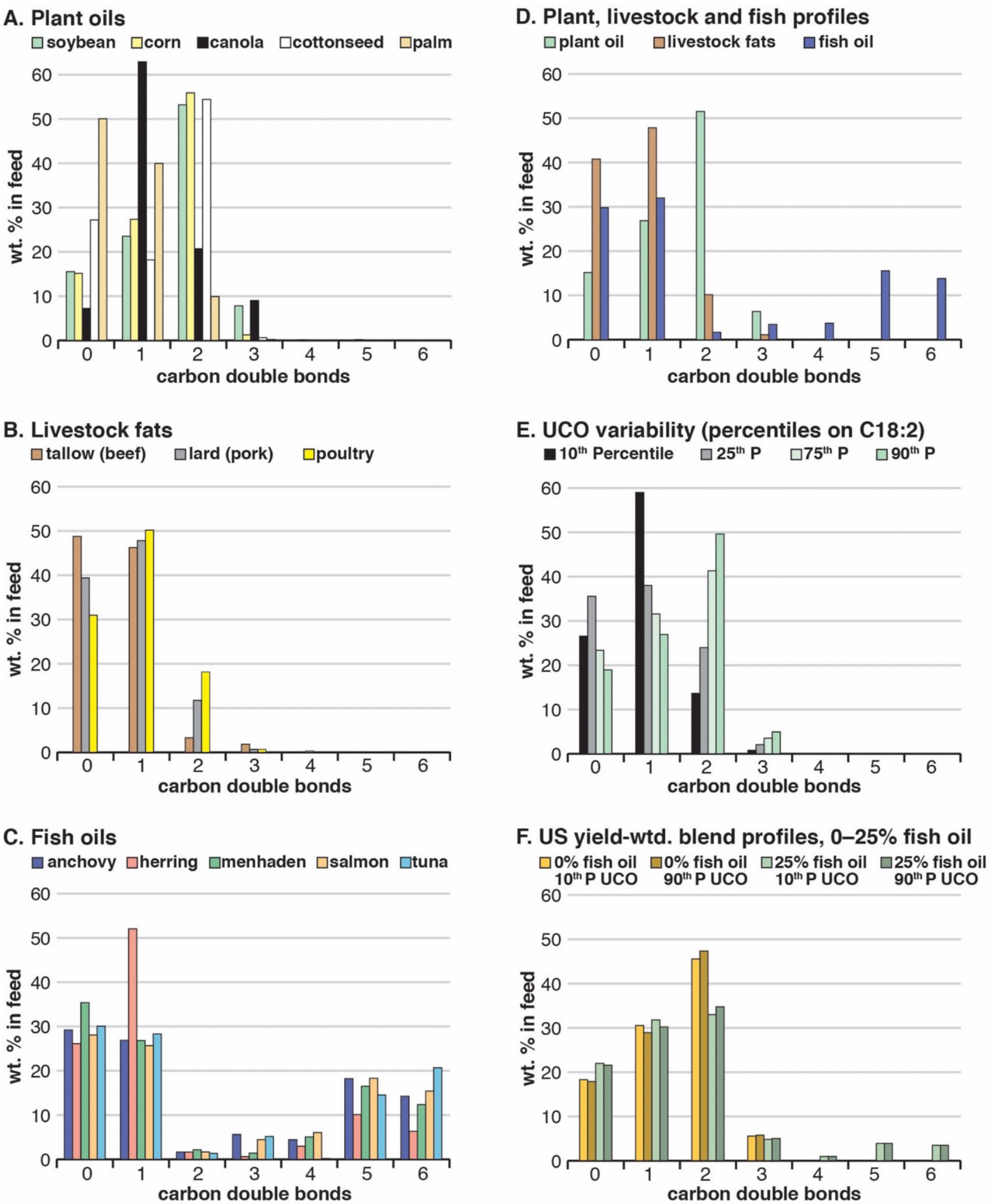
[38] See Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.
[39] See CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S.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



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

1.3.2 Types and locations of potential project biomass feed extraction

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

1.4 **Project Scale**

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

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

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

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

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

MM t/y: million metric tons/year

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

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

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

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

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

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

1.5 Project Operational Duration

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

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

1.6 Project Fuels Market

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

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

1.7 Project Scope

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

1.7.1 The Unit 250 diesel hydrotreater biofuel processing component

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

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

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

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

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

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

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

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

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

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

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

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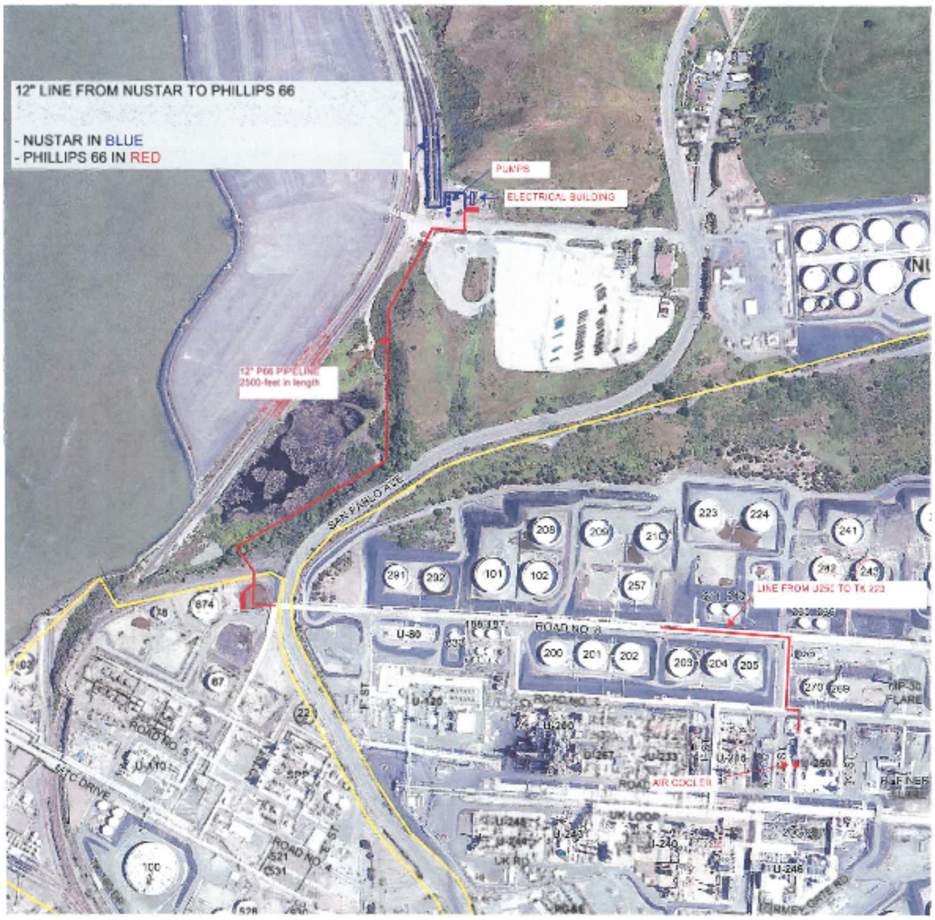
[59] BAAQMD, 2021 (Att. 14).
[60] Kupp, 2020a. Email text and attached site map from Gary Kupp, Contra Costa County, to Charles Davidson, incoming Rodeo-Hercules Fire Protection District director. 2 December 2020. Appended hereto as Attachment 15.
[61] *Id.*
[62] *Id.*



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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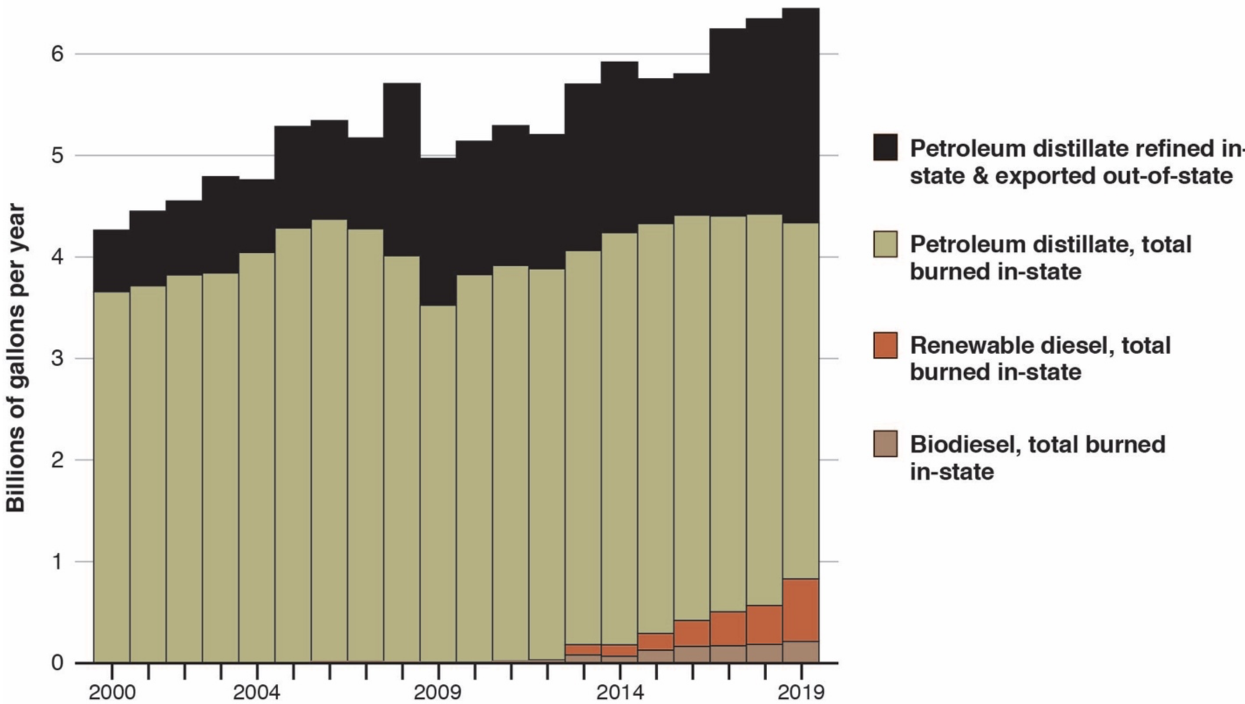
[74] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[75] "Project operations would decrease emissions of GHGs that could contribute to global climate change" (DEIR p. 2-5) including "indirect emissions" (DEIR p. 4.8-258) and "emissions from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

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



Distillate fuel shares associated with all activities in California, 2000–2019.
Growth in total distillates excluding jet fuel and kerosene from State data.
CHART 2. Data from CEC Fuel Watch (Att. 20) and CARB GHG Inventory (Att. 21).

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

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

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

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

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

Total volumes reported for ten-year periods

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

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

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

Comparisons of historic with recent California and West Coast data further demonstrate that this crude refining overcapacity for domestic petroleum fuels demand that drives the emission-shifting impact is unresolved and would not be resolved by the proposed project and the related Contra Costa County crude-to-biofuel conversion project. Fuels demand has rebounded, at least temporarily, from pre-vaccine pandemic levels to the range defined by pre-pandemic levels, accounting for seasonal and interannual variability. In California, from April through June 2021 taxable fuel sales[86] approached the range of interannual variability from 2012–2019 for gasoline and reached the low end of this pre-COVID range in July, while taxable jet fuel and diesel sales exceeded the maximum or median of the 2012–2019 range in each month from April through July of 2021. 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	Pre-COVID range (2012–2019)			Comparison of 2021 data with
	in 2021	Minimum	Median	Maximum	the same month in 2012–2019
Gasoline (MM gal.)					
Jan	995	1,166	1,219	1,234	Below pre-COVID range
Feb	975	1,098	1,152	1,224	Below pre-COVID range
Mar	1,138	1,237	1,289	1,343	Below pre-COVID range
Apr	1,155	1,184	1,265	1,346	Approaches pre-COVID range
May	1,207	1,259	1,287	1,355	Approaches pre-COVID range
Jun	1,196	1,217	1,272	1,317	Approaches pre-COVID range
Jul	1,231	1,230	1,298	1,514	Within pre-COVID range
Jet fuel (MM gal.)					
Jan	10.74	9.91	11.09	13.69	Within pre-COVID range
Feb	10.80	10.13	11.10	13.58	Within pre-COVID range
Mar	13.21	11.23	11.95	14.53	Exceeds pre-COVID median
Apr	13.84	10.69	11.50	13.58	Exceeds pre-COVID range
May	15.14	4.84	13.07	16.44	Exceeds pre-COVID median
Jun	17.08	8.67	12.75	16.80	Exceeds pre-COVID range
Jul	16.66	11.05	13.34	15.58	Exceeds pre-COVID range
Diesel (MM gal.)					
Jan	203.5	181.0	205.7	217.8	Within pre-COVID range
Feb	204.4	184.1	191.9	212.7	Exceeds pre-COVID median
Mar	305.4	231.2	265.2	300.9	Exceeds pre-COVID range
Apr	257.1	197.6	224.0	259.3	Exceeds pre-COVID median
May	244.5	216.9	231.8	253.0	Exceeds pre-COVID median
Jun	318.3	250.0	265.0	309.0	Exceeds pre-COVID range
Jul	248.6	217.8	241.5	297.0	Exceeds pre-COVID median

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

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

West Coast fuels demand in April and May 2021 approached or fell within the 2010–2019 range for gasoline and jet fuel and exceeded that range for diesel.[87] In June and July 2021 demand for gasoline exceeded the 2010–2019 median, jet fuel fell within the 2010–2019 range, and diesel fell within the 2010–2019 range or exceeded the 2010–2019 median.[88] *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 in 2021	Pre-COVID range (2010–2019) Minimum	Median	Maximum	Comparison of 2021 data with the same month in 2010–2019
Gasoline (MM bbl.)					
Jan	38.59	42.31	45.29	49.73	Below pre-COVID range
Feb	38.54	40.94	42.75	47.01	Below pre-COVID range
Mar	45.14	45.23	48.97	52.53	Approaches pre-COVID range
Apr	44.97	44.99	47.25	50.20	Approaches pre-COVID range
May	48.78	46.79	49.00	52.18	Within pre-COVID range
Jun	48.70	45.61	48.14	51.15	Exceeds pre-COVID median
Jul	50.12	47.33	49.09	52.39	Exceeds pre-COVID median
Jet fuel (MM bbl.)					
Jan	9.97	11.57	13.03	19.07	Below pre-COVID range
Feb	10.35	10.90	11.70	18.33	Below pre-COVID range
Mar	11.08	11.82	13.68	16.68	Below pre-COVID median
Apr	11.71	10.83	13.78	16.57	Within pre-COVID range
May	12.12	12.80	13.92	16.90	Approaches pre-COVID range
Jun	14.47	13.03	14.99	17.64	Within pre-COVID range
Jul	15.31	13.62	15.46	18.41	Within pre-COVID range
Diesel (MM bbl.)					
Jan	15.14	12.78	14.41	15.12	Exceeds pre-COVID range
Feb	15.01	12.49	13.51	15.29	Exceeds pre-COVID median
Mar	17.08	14.12	15.25	16.33	Exceeds pre-COVID range
Apr	15.76	14.14	14.93	16.12	Exceeds pre-COVID median
May	16.94	15.11	15.91	17.27	Exceeds pre-COVID median
Jun	14.65	14.53	16.03	16.84	Within pre-COVID range
Jul	16.94	15.44	16.40	17.78	Exceeds pre-COVID median

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

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

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

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

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

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

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

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

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

	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.

[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

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

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

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

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

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[129] *Id.*

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

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

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

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

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

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

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

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

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

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

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

3.2.5 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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3.2 <u>The DEIR air quality analysis failed to consider toxicological principles and practices</u>

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

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 <u>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</u>

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

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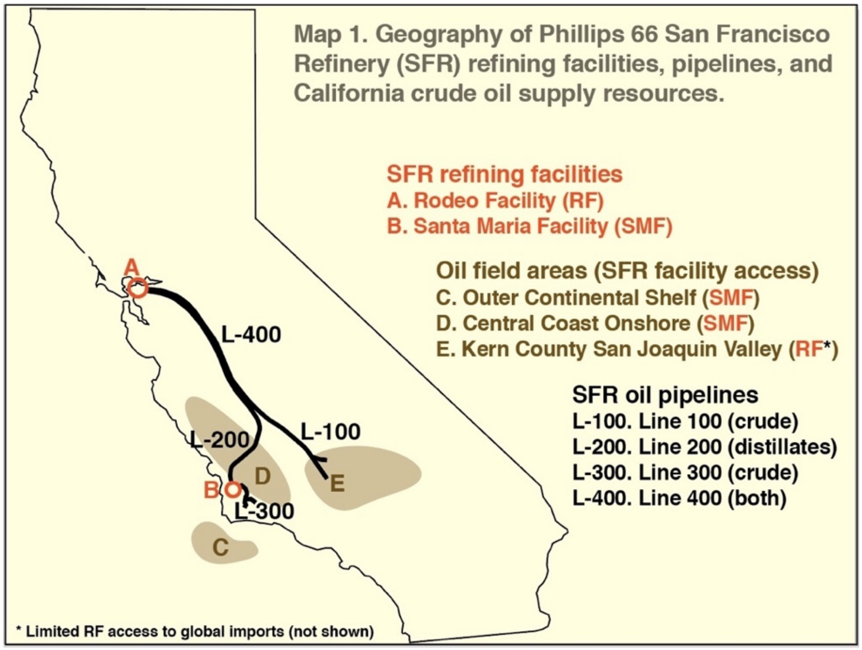
[155] The San Francisco Refining Complex (SFC) includes its Rodeo Refining Facility (RF), Santa Maria Refining Facility (SMF) and pipelines that feed crude to the SMF and crude blended with semi-refined oil to the RF.
[156] DEIR pp. 3-37 through 3-39; see also pp. 3-21, 5-12. Note that the DEIR picks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



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

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

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

[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.

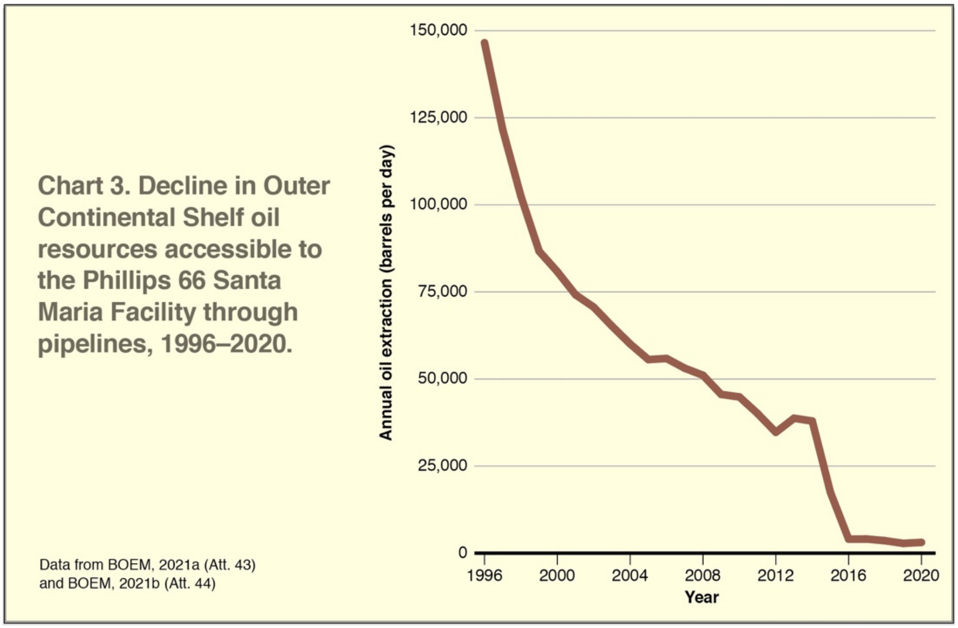

Chart 3. Decline in Outer Continental Shelf oil resources accessible to the Phillips 66 Santa Maria Facility through pipelines, 1996–2020.

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

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

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

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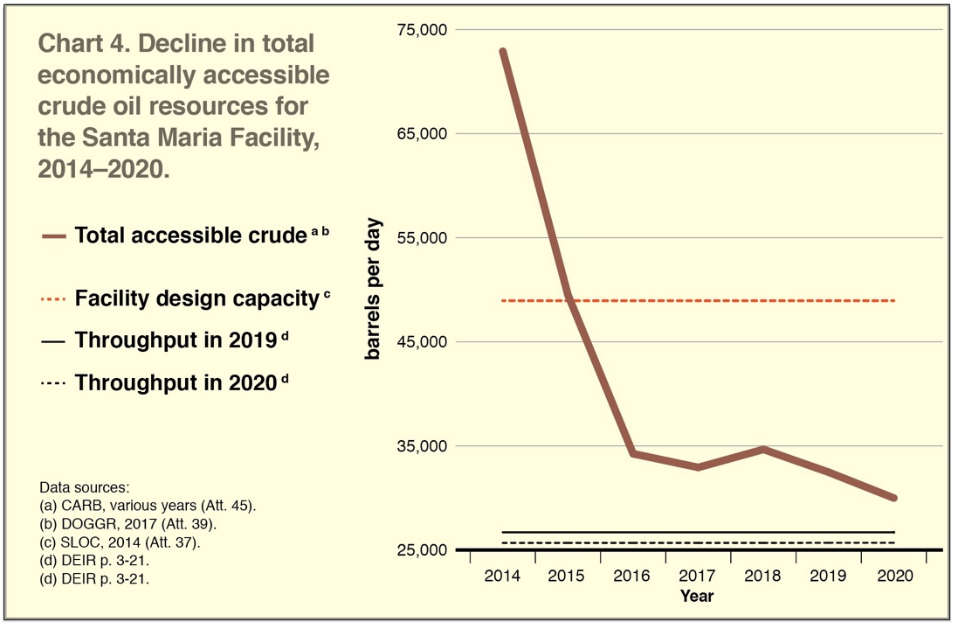
[181] These OCS oilfields that the SMF could historically or currently access via pipelines are the Point Pedernales, Point Arguello, Hondo, Pescado, and Sacate fields. *<u>See</u>* BOEM, 2021b (Att. 44).
[182] BOEM, 2021a (Att. 43).
[183] CARB, various years. *Calculation of Crude Average Carbon Intensity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



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

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

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

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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.

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

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

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

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

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

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33. 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.

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36. Sigma-Aldrich, 2021. *Safety Data Sheet: Hydrogen Sulfide;* Merck KGaA: Darmstadt, DE

37. 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.

38. CEC, 2021a. *Crude Oil Sources for California Refineries;* California Energy Commission: Sacramento, CA.

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

40. Perkins, 2019. Phillips 66 correspondence regarding Bay Area Air Quality Management District Permit Application No. 25608.

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ATTACHMENT B

TECHNICAL SUPPLEMENT

Greg Karras

Senior Scientist, Community Energy reSource

1. The FEIR DOES NOT PROVIDE FACTUAL SUPPORT FOR THE IMPROPERLY INFLATED REFINERY BASELINE IN THE DEIR

1.1 The FEIR Does Not Respond to Comment on a Lower Non-zero Baseline

Comment 36 identified, described in detail, and supported with substantial evidence in a technical report (Comment 36 "Appendix C") serious deficiencies in the DEIR baseline analysis, which has the effect of obscuring significant impacts. The evidence presented supports a finding that the DEIR baseline analysis fails to represent existing conditions, including an existing, worsening limitation on access to crude feedstock, unique to the project site refining facilities, that has driven crude refining rates and thus environmental impacts of refining lower than those in the DEIR baseline analysis. Hence, should the proposed project not be implemented, crude refining is more likely to shutter than return to and maintain higher historic rates at one, or both, project refining facilities, due to this worsening crude access limitation.[1]

The FEIR responses to these comments cross-reference to FEIR Master Response 1,[2] which mischaracterizes these comments as stating "that these baselines are inappropriate, and instead suggest that the appropriate baseline is a future scenario under which neither the Rodeo Refinery nor the Santa Maria Refinery exist."[3] The FEIR then discusses the baseline only in the context of responding to this strawman characterization, which drastically skews the meaning of Comment 36. The comment did not request a baseline in which the Rodeo and Santa Maria refineries simply do not exist; but rather called upon the County to consider their rapidly decreasing access to feedstock in setting the baseline and defining the no-project scenario.

The FEIR does not respond to factual comments describing evidence for existing conditions that reduced refining rates and emissions to non-zero levels, or to factual comments regarding the likelihood of one, rather than both, crude refining facilities closing. Master 1 thus fails to frame a factual response to evidence provided in comment that the DEIR baseline was improperly inflated, irrespective of whether or not a refining facility will close.

1.2 The FEIR Admits to the Physical Mechanism Which Has Caused Project Refining Facilities to be Uniquely Crude Supply-limited

1.2.1 Comments on the DEIR described the cause of supply limitations in detail

As described in comments,[4] the DEIR did not disclose, evaluate, or accurately describe the functional interdependence of San Francisco Refining Complex (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.[5]

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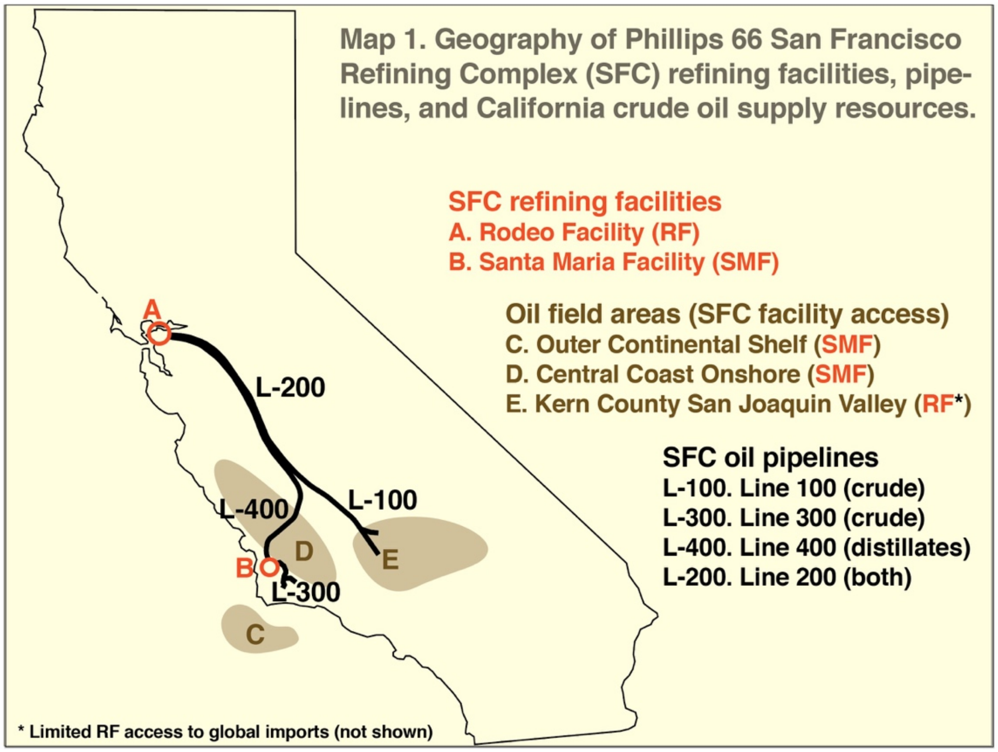
[1] Comment 36 Section III; Comment 36 Appendix C Section 5.
[2] FEIR at 3-328 to 3-338, 3-592, 3-593 (responses 50–64); 3-574 to 3-582, 3-623, 3-624 (responses C-46 to C-58); 3-3 to 3-15 (Master Response 1).
[3] FEIR at 3-3. *See* also FEIR at 3-13, 3-14.
[4] In particular, comment 36, Appendix C, Section 5. This excerpt herein is revised to match lines labels in the EIR.
[5] Map 1 is only approximately to scale, but otherwise consistent with facility and pipeline maps in the DEIR.



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. The SMF ("B") has no seaport access to import foreign or Alaskan crude via marine vessels[6] which other refineries rely on for most of the crude refined statewide.[7] It receives crude only via its locally connected pipeline, limiting its access to crude from outside the local area almost entirely.[8]

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.[9] Outer Continental Shelf (OCS) oilfields off northern Santa Barbara County supplied up to 85% of SMF crude as of 2014,[10] but that 85% came from only a few OCS fields ("C") which had pipeline connections to the local SMF pipeline system ("L-300").[11]

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[6] 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. Attachment 37 to Appendix C of Comment 36.
[7] *Crude Oil Sources for California Refineries;* California Energy Commission: Sacramento, CA. (CEC, 2021a). Attachment 38 to Appendix C of Comment 36.
[8] SLOC, 2014. Attachment 37 to Appendix C of Comment 36.
[9] *Id.*
[10] *Id.*
[11] 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 (Attachment 44 to App. C of Comment 36).

The DEIR did not disclose the lack of SMF seaport access—which crucially limits its feed access almost entirely to local OCS and onshore crude—then obscured the larger effect of this on 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 400 from the SMF and Line 200 to the RF, where the Kern crude and semi-refined SMF output flow north through Line 200 to the RF.[12] But the DEIR described 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 obscured the fact that the SMF lacks economic access to San Joaquin oilfields—and further obscured the mix of oils flowing through Line 200 to the RF.

These existing conditions in the project setting that the DEIR omitted or described inaccurately have a profound systemic effect on the project baseline. Instead of pipeline access to the largest regional crude resource in California[13] as the DEIR wrongly described, the SMF lacks both that access, and seaport access to imports that provide the largest source of crude refined statewide,[14] 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.[15] 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 200 cannot physically function effectively without input from the SMF. The less viscous SMF output[16] thins the viscous (thick like molasses) San Joaquin Valley Heavy crude ("E" in Map 1), enabling it to move efficiently through Line 200 ("L-200") to the RF. Loss of SMF feed input and hence Line 200 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.

[12] 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 400. 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.
[13] 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. Attachment 39 to Appendix C of Comment 36.
[14] CEC, 2021a. Attachment 38 to Appendix C of Comment 36.
[15] DEIR p. 5-3.
[16] Naphtha, distillates and gas oil ("pressure distillate") from crude accessed and partially refined by the SMF, then sent through lines 400 and 200 to the RF for gasoline, diesel, and jet fuel production.

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 did not disclose or evaluate this crisis in its baseline analysis.

1.2.2 The FEIR admits a substantive project setting description error in the DEIR that is relevant to its baseline analysis

As stated, the DEIR erroneously described Line 100 as directly supplying the SMF with crude from the largest regional crude resource in California in Kern County, obscuring both the extreme crude access limitation of the SMF and the mix of oils in the pipe to the RF, hence the crucial thinning of that San Joaquin Valley Heavy crude by partially refined SMF output. The FEIR admits that error, and further signals its importance by proposing corrected DEIR text which could allow careful review to glean these crucial parts of the DEIR project description for baseline analysis.[17] The DEIR should have been recirculated for public comment given the fundamental significance of that error to the analysis.

1.2.3 The FEIR does not factually rebut evidence that crude supplies to both refining facilities are affected by declining access to Central Coast onshore and offshore oil

The FEIR agrees with comments that recent declines in crude supplies accessible to the SMF have impacted project site refining rates in multiple parts of its text.[18] It even quantifies part of that refining impact.[19] The FEIR also states that "the quantity of feedstock delivered to the Rodeo Refinery via pipeline from the Santa Maria Refinery has been relatively low since 2015" because of reduced access to crude extraction from Central Coast offshore oilfields via pipeline.[20] Further, it cites an alternative to loss of thinning oil "diluent" production at the SMF which would "reduce the rate at which Line 200 operates, which proportionately requires that less diluent be added to the crude oil shipped northward" in the Line 200 pipe to the RF.[21] The FEIR does not question that declining SMF crude supplies already affect both refining facilities.

1.2.4 The FEIR indirectly supports factual comment that existing infrastructure constrains RF pipeline crude supply from the San Joaquin Valley due to SMF crude rate cuts

That FEIR discussion of pipeline crude for the RF reduced "proportionately" to diluent added in Line 200[22] confirms the impact of lost SMF thinning oil on RF access to San Joaquin Valley crude via pipeline that is discussed in §§ 1.2.1. Still further, it cites theoretical options for replacing loss of its existing pipeline input to the RF should the SMF shut down.[23] Thus, the FEIR supports comments that existing project site infrastructure and operations limit and further reduce pipeline supplies of crude as well as partially refined SMF output to the RF when declining SMF crude supplies further reduce SMF refining rates.

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[17] FEIR at 3-8, 3-9. The FEIR, however, continues the DEIR failure to disclose or address the full significance of this error with respect to accurate description of current and near-term future baseline conditions. For example, stating at 3-8 that it did not alter numbers the FEIR specifies that it derived from *historic* conditions in 2019.
[18] FEIR at 3-6, 3-7, 3-9, 3-14.
[19] See the untitled table at FEIR 3-7.
[20] FEIR at 3-7.
[21] *Id.*
[22] *Id.*
[23] FEIR at 3-6, 3-9, 3-12.

1.3 The FEIR Admits to Declining Santa Maria Facility (SMF) Crude Rates Caused by the Currently Dwindling Crude Supply Accessible to the SMF

1.3.1 The FEIR agrees with factual comment that SMF crude refining rates have declined

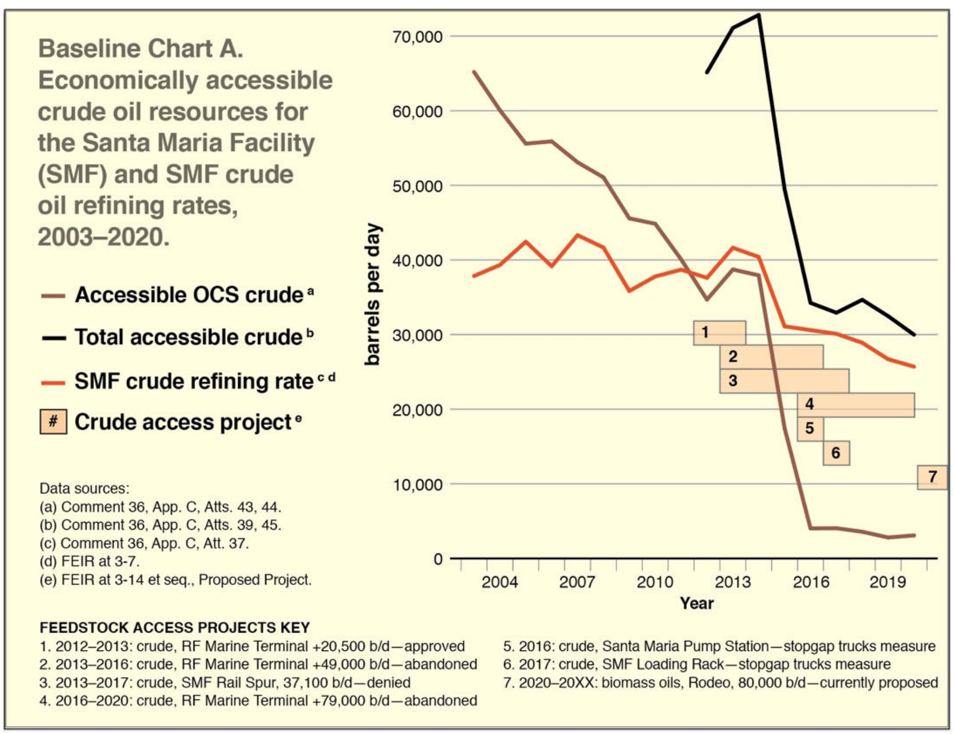
FEIR Master Response 1 states repeatedly that SMF crude rates have declined recently, and quantifies that decline from 2014 through 2020.[24]

1.3.2 The FEIR asserts that declining crude supplies accessible to the SMF via pipeline caused declining SMF crude refining rates

Master Response 1 asserts that declining crude supplies accessible to the SMF, and in particular declining crude supplies for the SMF from Outer Continental Shelf (OCS) oil fields due to loss of pipeline access to shut-in OCS oil fields, caused the SMF to cut refining rates.[25]

1.3.3 New data in the FEIR further support an ongoing trend of significantly declining SMF crude rates driven by declining supplies of accessible crude for the SMF.

FEIR Master Response 1 reports SMF crude rates for 2014 through 2018.[26] SMF crude rates were reported in the DEIR only for 2019 and 2020. Together with crude rate and crude supply data reported in comment on the DEIR,[27] the newly reported data in the FEIR further support a strong trend of declining SMF crude rates that has been clearly associated with declining SMF crude supplies since 2013 and has continued since 2016. *See* Baseline Chart A.



[24] FEIR at 3-6, 3-7, 3-14.
[25] FEIR at 3-6, 3-7, 3-9, 3-14.
[26] *See* the untitled table at FEIR 3-7.
[27] *See* attachments 37, 39, 43–45 to Comment 36 Appendix C.

1.4 The FEIR Fails to Provide Relevant Evidence for its Assumption that Currently Nonexistent Access to Crude Supplies will Materialize Absent the Project

The FEIR asserts that if the biorefining project does not proceed Phillips 66 or others could simply implement new projects that will tap new crude supplies for the Santa Maria and Rodeo refining facilities. However, those hypothetical projects do not currently exist for the SMF or RF.[28] None of them has been approved, and built. Many have not been proposed. The FEIR does not provide evidence that any specific new RF or SMF crude access project will be implemented. It cites historic conditions for oil supply expansion which now have changed, while ignoring site-specific current evidence that points in the exact opposite direction.

1.4.1 Phillips 66 has tried and failed to implement new crude access projects for the RF and SMF since 2013

None of the projects Phillips 66 proposed since 2013 which could have accessed new crude supplies outside Central California for the SMF and RF in amounts comparable to the Central Coast crude supply decline that has already occurred was implemented. *See* Chart A. Projects of the type that the FEIR assumes would quickly resupply dwindling current crude oil sources by tapping new crude sources in significant amounts proved unable to launch at the SMF and RF over the most recent seven to nine years (*Id.*). The FEIR baseline responses ignore this.

Thus, available evidence for existing conditions indicates that despite its worsening crude supply crisis, Phillips 66 has not been able to access new crude feedstock sources for project refining sites. Remarkably in this regard, the FEIR suggests that switching refinery equipment to the biofuel project itself could be a reaction to the growing crude supply constraints.[29] Rather than crude refining at historic rate being the default, currently lower and declining crude refining rate is the default if the biofuel project does not proceed—the project baseline.

1.4.2 The FEIR does not respond to comment showing that existing state climate policies and technology trends are further reducing the likelihood of large new crude supply infrastructure projects by further reducing the need for petroleum fuels

A confluence of technology change which is decarbonizing electricity while electrifying transportation and state climate policy standards and goals for zero-emission vehicles could reduce needs for petroleum, thereby increasing the uncertainty of already-uncertain prospects for approval, financing, and implementation of new projects to access new sources of crude. DEIR comments provided substantial evidence that this shift in energy impact conditions affects fuels and refining, and hence future petroleum infrastructure.[30]

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[28] The DEIR did not describe infrastructure projects to access new sources of crude, and the FEIR refers to a range of them in vague and hypothetical terms: One might take crude from Line 100 in the San Joaquin Valley (SJV) to the SMF in trucks or the RF via trucks or trucks to barges or trucks to vessels (FEIR at 3-6). Another might add another source of diluent to Line 200 to pipe SJV crude to Rodeo (3-7). A third might build new pipelines (3-12). Future projects to build oil train unloading facilities (3- 12) or expand marine terminal throughput (3-6, 3-10, 3-12) would, presumably, be resurrected from past proposals at the SMF, or RF, respectively. The FEIR discusses the possibility of SMF pipeline connection to the proposed rebuild of the Plains All America pipeline in County, should that project, which Santa Barbara County has long studied, be approved and built (3-6, 3-9).

[29] FEIR at 3-12 ("With respect to how Phillips 66 might react to further constraints of the historically-available crude oil supply resources for the Santa Maria Refinery, some future adjustments include ... processing pre-treated renewable feedstocks in other existing units").

[30] *See* Chapter 4 of Attachment A to Comment 36; §§ 2.2 of Attachment C to Comment 36.

Among other results of this shift in energy impact conditions, post–COVID-vaccine data show that some 222,000 to 305,000 barrels per day of operable crude refining capacity—far more than the 120,200 b/d total capacity of the RF and SMF combined—sat idle statewide in 2021.[31] Indeed, the Phillips 66 proposals that failed to expand SMF and RF access to new sources of crude listed in Chart A and discussed in §§ 1.4.1, were each contested over their attendant environmental impacts, and rejected or stalled and abandoned in this context of this shift in energy impact conditions.

Responses to baseline comments in the FEIR do not respond to this comment issue.

Thus, to the extent that the site-specific evidence for existing conditions described in Chart A and §§ 1.4.1—that projects to access new sources of crude have not proceeded—is further informed by relevant technology (e.g., EVs) and energy-climate policy (e.g., ZEVs), it has made new projects to extract, refine, and burn new sources of petroleum even less plausible.

[31] *See* §§ 2.2 of Attachment C to Comment 36.

2. THE FEIR FAILS TO ACKNOWLEDGE UNDISCLOSED BIOREFINING IMPACTS OF NON-PETROLEUM PROJECT COMPONENTS WHICH DEBOTTLENECK EXCESS BIOREFINING

As explained in the Comments, the DEIR did not identify, describe, or evaluate environmental impacts from increased biorefining rates caused by a process impact that could "debottleneck" project biofuel hydro-conversion rates far exceeding those the DEIR evaluated.[1] These impacts would be connected to use of petroleum processing equipment retained in the project, including existing catalytic reformers. At stake is the potential for unmitigated impacts caused by hydro-production–driven biorefinery expansion from disclosed project equipment with this undisclosed impact on HEFA biofuel refining.[2] FEIR responses to this comment cross-reference Master Response 5, except for one short narrative response discussed below.[3]

2.1 The FEIR fails to respond to or address comment concerning undisclosed potentially significant impacts associated with <u>biofuel processing and feedstock acquisition</u>.

Response 46 responds narrowly regarding only direct impacts of non-biofuel process equipment. However, this misses the point of the comment regarding debottlenecking. As stated in the comment, the debottlenecking impact could contribute to expanding project biorefining and associated impacts in excess of refining rates assessed in the DEIR without the subject process equipment directly processing biofuels. The cross-referenced Master 5 does not touch on potential impacts associated with further expanded biofuel feed acquisition or processing in excess of levels evaluated in the DEIR.

2.2 The FEIR dismisses the process debottlenecking effect based on faulty logic.

Master Response 5 argues that there is no "bottleneck" which the subject processing equipment could relieve by boosting hydrogen supplies for increased biorefining rates, essentially dismissing this comment entirely. Specifically, it asserts that the existing hydrogen plants would supply sufficient hydrogen, so that additional hydrogen would have no effect on biorefining rates.[4] However, it draws that conclusion from processing capacities "as set forth in the DEIR," meaning *the same biorefining rate that the DEIR evaluated*, as a following page confirms.[5] In other words, the response dismisses comment about the potential for an undisclosed source of project hydrogen to increase biorefining rates and process impacts based on its comparison that assumes in the first place that those biorefining rates will not increase. The reasoning is entirely circular.

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[1] Comment 36 §§ II.B.3; Comment 36 App. C §§ 1.7, 1.7.3.
[2] *Id.*
[3] FEIR Response C-18 at 3-620; FEIR responses 44 to 48 at 3-591, cross-ref. to Master Response 5 at 3-39 to 3-49. Only response 46 includes a brief narrative (FEIR at 3-591) in addition to cross-referencing Master 4 as does each other response to this topic in Comment 36. Response 46, however, improperly narrows the environmental impact scope of the comment to exclude impacts associated with increased biofuel processing and related feed acquisition impacts which are a crucial focus of the comment included in it explicitly. This is an incomplete response at best.
[4] FEIR at 3-42.
[5] *Compare* FEIR at 3-42, 3-44 (67,000 b/d biorefining rate compared, not 80,000 b/d excess comment was about).

Moreover, data and information reported in the FEIR under a different subtopic[6] confirm essentially the same result as the comment. Namely, disclosed hydrogen plant supplies of hydrogen for biorefining appear able to support the 67,000 b/d evaluated for impacts in the DEIR, but not processing the 80,000 b/d biomass feed pretreatment plant output in the project. Additional hydrogen from the catalytic reformers could supply that shortfall at 80,000 b/d biorefining rates. This is based on data from the FEIR as noted above, and process capacities in the Phillips 66 Title V air permit which is in the record. The spreadsheet image below shows this back-of-the-envelope calculation from the data.

Back of the envelop calculation for project hydrogen bottleneck, U44+231 reformers debottleneck
(Based on data and methods summarized in FEIR at 3-43, 3-44. Unit capacities from Air Permit)

	Calcs: b/d feed	Low end SCF/b H2	High end SCF/b H2	Low end MMScfd H2	High end MMScfd H2	2 H2Ps MMScfd	Bottleneck? (% H2Ps)	Bottleneck? (% H2Ps)
At capacity	120,740	2,071						
U240/246	69,000	2,500						
U248	16,740	1,500						
U250	35,000	1,500						
U244+231	39,000	1,000						
At 67kb/d	67,000	2,072	2,210	139	148	149	107%	100%
U240/246	38,294	2,500	2,500	96	96			
U248	9,290	1,500	2,500	14	23			
U250	19,424	1,500	1,500	29	29			
U244+231	21,644	1,000	1,000	22				
At 80kb/d	80,000	2,071	2,210	166	177	149	90%	84%
U240/246	45,718	2,500	2,500	114	114			
U248	11,092	1,500	2,500	17	28			
U250	23,190	1,500	1,500	35	35			
U244+231	25,841	1,000	1,000	26		174	105%	99%
				Add 26 MMScfd/b to 149 MMScfd from hydroegn plants				
				and 174 ÷ 166 = hydrogen to run at 80.000 b/d				
U240/246	hydrocrackers		U250	Hydrotreater				
U248	hydrotreater		U244+231	Catalytic reformers				

6 FEIR at 3-43, 3-44.

3. THE FEIR DOES NOT REBUT FACTUAL EVIDENCE THAT REVERSES THE LESS-THAN-SIGNIFICANT GHG EMISSIONS IMPACT FINDING IN THE DEIR

The Comments showed, based on authoritative state and federal data, that project production of the particular type of biofuel proposed by Phillips 66[1] would cause and contribute to a significant potential greenhouse gas (GHG)[2] emissions impact by adding to petroleum diesel refining and combustion instead of replacing petroleum fuels as presumed in the DEIR.[3] Comments further showed that this would result in a net increase in GHG emissions, reversing the conclusion in the DEIR—which did not disclose or evaluate the information presented in comment—that incorrectly ascribed a less-than-significant GHG impact to the project.

The FEIR responds to this comment by cross-referencing Master responses 4 and 5.[4] Master Response 4, however discusses land use and feedstocks; it does not touch on the topics or information presented in this comment.

3.1 The FEIR fails to consider the scope and scale of GHG impacts identified by comment.

Climate impacts caused by GHG emissions are well known to be fundamentally cumulative and global, as the FEIR itself asserts in its statement of GHG emission impact evaluation scope. FEIR at 3-24, Table 6-1. Yet the FEIR takes the position that the comment concerning global impacts of the project GHG emissions "is not valid, because the Draft EIR did not consider those GHG reductions in determining that the impact was less than significant. FEIR at 3-47. This position, intentionally excluding global impacts from the climate analysis, represents an additional error.[5]

3.2 The FEIR's assertions concerning global petroleum diesel use are unsupported and flawed.

The FEIR correctly observes that petroleum distillate exports contribute to continued or increase global combustion of this fuel (instead of replacing it) when "overall use of petroleum distillate either remained the same or increased." FEIR at 3-48. However, it then states: "Supply from California could be replacing other sources globally"[6] without citing any factual support for that supposition. *Id.* In fact, actual data the FEIR fails to disclose indicates that total world usage and hence combustion of distillate-diesel fuels is steadily increasing, as illustrated in Chart B.

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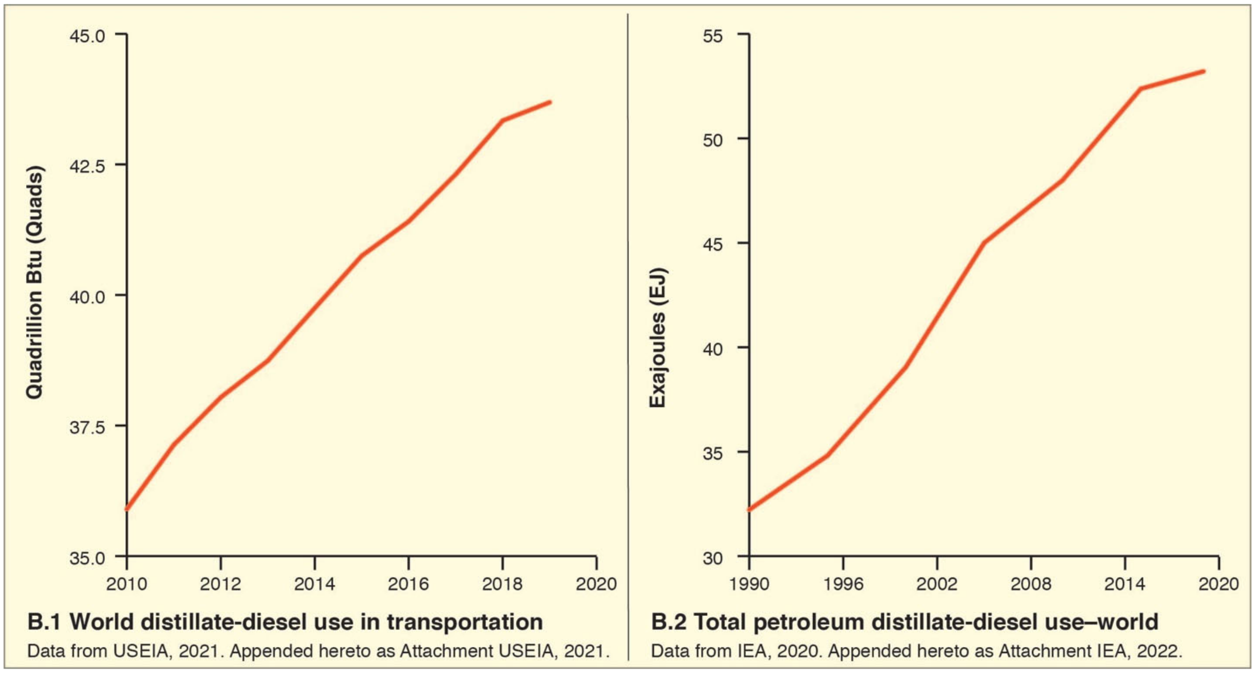
[1] Hydrotreated Esters and Fatty Acids (HEFA).
[2] Herein, GHG means carbon dioxide equivalents (CO_2e) at the 100-year climate forcing horizon.
[3] Comment 36, Appendix C, § 2; *see also* Comment 36 §§ VI.C.
[4] Responses to Comment 36 C-19 through C-23 and 112 through 115, FEIR at 3-620, 3-621 and 3-598, cross-referencing Master responses 4 and 5, FEIR at 3-29 through 3-49, except for an incorrect conclusion that CEQA does not require evaluation of a potential impact it associated with the comment (Response C-20 at 3-620).
[5] The reference to "GHG reductions" in this quote from the FEIR follows its speculation, at 3-47 that the comment fails to account for the difference between full fuel chain (life cycle) emissions from petroleum and those from HEFA diesel. That is incorrect. The comment uses state emission factors to account for this difference (FEIR at 3-559, Comment Table 7) and shows HEFA diesel *has not* replaced petroleum diesel emissions (FEIR at 3-552 to 3-559).
[6] FEIR at 3-48.



B.1 World distillate-diesel use in transportation
Data from USEIA, 2021. Appended hereto as Attachment USEIA, 2021.

B.2 Total petroleum distillate-diesel use–world
Data from IEA, 2020. Appended hereto as Attachment IEA, 2022.

Global use of distillate-diesel in transportation rose steadily over the most recent ten years reported by the US Energy Information Administration,[7] from approximately 35.9 quadrillion Btu in 2010 to approximately 43.7 Quads in 2019—growing by nearly 22 percent over this decade. Global use of total petroleum distillate[8] rose steadily from approximately 32 exajoules (EJ) in 1990 to 53 EJ in 2018, growing by 65 percent in this 20-year period.[9] Thus, evidence that the FEIR does not disclose further supports the GHG impact shown by comments.

3.3. The FEIR fails to respond to comments concerning the export impact of adding HEFA diesel into the in-state distillate-diesel fuel pool.

The Comments showed that California refineries export a substantial portion of their petroleum diesel production to other states and nations, and protect their otherwise-stranded refining capacity assets by increasing those exports when in-state demand for petroleum diesel declines.[10] Thus, by adding HEFA diesel to the in-state diesel pool, thereby reducing in-state demand for petroleum distillates, the project would have the effect of increasing petroleum distillate exports from other California refineries.[11] The FEIR argues that the project could not possibly contribute to that in-state capacity *versus* demand gap since it would reduce petroleum distillate production at the Phillips 66 refinery in Rodeo to zero. FEIR at 3-48. However, this ignores the aspect of the comment showing that the statewide capacity gap is much larger than the Rodeo and Santa

[7] USEIA, 2021 (attached to this technical supplement).
[8] The International Energy Agency (IEA) reports petroleum distillates as Gas/Diesel, which includes diesel oils and light heating oil but excludes motor gasoline and excludes jet fuel.
[9] EIA 2022 (attached to this technical supplement).
[10] Comment 36, Appendix C, § 2.
[11] Comment 36, Appendix C, § 2. Note that in addition to the Rodeo and Santa Maria facilities, Phillips 66 owns and operates an even larger Los Angeles crude refinery.

Maria facilities capacity combined. Thus a very substantial portion of statewide refining capacity would remain idled should the project proceed—and send more than a million new biofuel gallons to the in-state diesel pool daily, both enabling and incentivizing the resultant further increased petroleum distillate exports.[12]

3.4 The FEIR <u>does not</u> rebut evidence provided in comments showing that the project could cause and contribute to significant GHG emission impacts by adding diesel biofuel emissions to petroleum diesel combustion <u>instead of</u> replacing petroleum distillates.

The Comments showed that by adding HEFA diesel to the California fuels market it would add combustion emissions from the full fuel chain of that diesel biofuel, at the same time emissions from the petroleum distillate-diesel burned in California and (increasingly) exported continue.[13] The FEIR argues that the project is not linked to increased emissions from fuels produced by other refiners, and further implies that this is shown by the comment calculation of emissions from petroleum distillates instead of project biofuel. FEIR at 3-48. However, this response fails to acknowledge the key fact that HEFA diesel has in fact *failed to replace* petroleum distillate in California discussed above; as well as the direct link between the project and its emissions as estimated based on state default emission factors for HEFA biofuel.[14] In fact, the Comments identified significant GHG emissions from the project-produced biofuel that would not replace petroleum fuel *alone.*[15] Those emissions—again, undisclosed by the DEIR and hence not accounted for by it—would be in the range of several million metric tons per year, hundreds of times the EIR significance threshold of 0.01 million tons.[16]

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[12] Comment 36, Appendix C, §§ 2.2.
[13] Comment 36, Appendix C, § 2. *<u>See</u>* esp. Table 7 in §§ 2.2 (showing the calculation of emission impacts is specifically based on fuel chain emissions from project diesel biofuel that does not replace petroleum).
[14] *Id.*
[15] *Id.*
[16] *Id.*

4. FEIR RESPONSES TO COMMENT ON PROCESS HAZARDS AND FLARING FURTHER DEMONSTRATE THE NEED TO RECIRCULATE A REVISED DEIR

4.1 The FEIR Reports and Relies Upon Substantial New Information Never Disclosed, Evaluated, or Provided for Public Review and Comment by the DEIR

In response to the portions of the Comments stating that process design and operating conditions specification data necessary to sufficient project hazards evaluation were undisclosed in the DEIR,[1] the FEIR makes numerous additional disclosures on these subjects. These disclosures, while still incomplete, represent a mountain of last-minute data and information being presented to the public with no opportunity for meaningful analysis and comment. Specifically, the FEIR comment response presents dozens of newly asserted statements about relevant project hazard issues, which it ascribes to some 18 newly identified technical references[2] - or in some instances to no cited reference at all.[3] Therefore, the DEIR must be revised and recirculated for public review and comment.

4.2 The FEIR Fails to Disclose or Evaluate Crucial Process Safety Information Identified by Comment but Never Provided in the DEIR

The Comment identified and described the importance of Process Hazard, Hierarchy of Hazard Control, Inherent Safety Measure, Safeguard, and Layer of Protection analyses—a sequence of rigorous, formally documented analyses. It noted that the DEIR did not disclose or include these essential components of project hazards evaluation, and indicated that the County could use them to address this deficiency in the DEIR.[4] The FEIR hazards comment response still does not include or disclose Process Hazard, Hierarchy of Hazard Control, Inherent Safety Measure, Safeguard, and Layer of Protection analyses for the project (Master Response 5). Thus, it does not cure this deficiency in the DEIR.

4.3 The FEIR Fails to Disclose or Evaluate Relevant Available Information that Indicates a Reasonable Potential for Significant Project Flaring Impacts

4.3.1 Substantial site-specific evidence for significant flaring

The Comments identified and provided substantial site-specific evidence that multiple frequently recurring flaring incidents involving the same refining equipment the project would repurpose, and the same types of hydrogen-related causal hazards it would present and intensify, resulted in significant impacts as measured by regional flaring thresholds.[5] The FEIR failed to include or adequately consider this highly relevant information for project hazard, air quality, and public health evaluation.

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[1] Compare Appendix C of Comment 36, §§ 1.1 through 1.5 and 3.1 with FEIR Master Response 5.
[2] FEIR at 3-45 through 3-47.
[3] FEIR Master Response 5.
[4] Appendix C of Comment 36 at §§ 3.1.
[5] Appendix C of Comment 36 at §§ 3.2.1 through 3.2.4 and § 4.

4.3.2 Previously undisclosed evidence for fuel gas-imbalance flaring known to Phillips 66

The FEIR concludes that project flaring impacts would be less than significant (Master Response 5) and does not change the project description, which calls for the removal of multiple currently operating process units, including fired heaters or furnaces, from service. The FEIR fails to disclose that this type of reduction in the numbers of interconnected and interrelated equipment and process units in the new biorefinery could *cause* impacts by contributing to specific process and flaring hazards in hydro-conversion reactors.[6]

Specifically, other refiners often rely on multiple large furnaces, heaters, or turbines that are net fuel gas consumers to control fuel gas imbalances and overpressures and mitigate resultant flaring. Reducing the number and fuel consumption capacity of fired sources such as the furnaces, heaters and turbines reduces the availability and effectiveness of that safeguard significantly. Further, the FEIR suggests reduced firing for project process units—hydro-conversion process units[7]—that are large net fuel gas producers, thus potentially worsening fuel gas imbalance hazards by adding net gas producers while subtracting net gas consumers.

Review of causal analysis reports for the frequent environmentally significant refinery flare incidents provided in DEIR comment[8] would reveal substantial evidence for the potential significance of removing this de facto process hazard and flare minimization safeguard.

Moreover, Phillips 66 has identified this hazard to air quality officials outside the present CEQA review—the need for fuel gas consuming equipment to prevent and mitigate fuel gas imbalance flaring and limitations of sufficient fuel gas consumers to do so—in far more specific detail than provided in the DEIR and FEIR. Its currently approved Flare Minimization Plan, which shows Phillips 66 has identified this same flaring cause and discussed it more candidly outside the EIR, is appended hereto.[9] This important evidence for project potential to result in significant impacts associated with flaring was not disclosed, included or evaluated in the DEIR or FEIR.

[6] *See* Comment 36, Attachment C, part 5 for details of hydrogen-related and damage mechanism hazards.
[7] FEIR at 3-45.
[8] *See* Comment 36, Attachment C, part 5 and Attachment 26 thereto.
[9] Phillips 66 FMP, 2020. Phillips 66 San Francisco Refinery, Rodeo, California, BAAQMD Plant 16, Flare Minimization Plan – 2020 Revision. Public Version. October 2020. Appended hereto as "Phillips 66 FMP."

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total World		49-IEO2021.1.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	42.2498	42.5267	43.1843	44.5592	45.3862	46.1297	47.2757	47.6391	48.1	49.6281	44.4808	46.7837	48.1062	48.9815	49.588	50.0932	50.5062	50.841	51.1736	51.4703	51.7613
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	35.8984	37.1266	38.0358	38.7383	39.7488	40.7514	41.4118	42.3066	43.343	43.6874	40.3139	42.4607	43.6865	44.4771	44.8839	45.2337	45.3799	45.3755	45.3592	45.2754	45.1738
Residual fuel oil	Transportati	49-IEO2021.4	quad Btu	8.1619	8.0385	7.7732	7.7327	7.615	7.5117	7.794	7.9493	8.0021	8.3583	8.0861	8.2944	8.7405	8.787	8.8439	8.7914	8.77	8.7481	8.7489	8.77	8.8449
Liquefied petroleum gas	Transportati	49-IEO2021.5	quad Btu	0.6777	0.6863	0.6817	0.6663	0.6491	0.6312	0.6198	0.6201	0.6104	0.6174	0.4914	0.5357	0.5545	0.5635	0.5625	0.5555	0.5454	0.5364	0.5257	0.5141	0.5014
Jet fuel	Transportati	49-IEO2021.6	quad Btu	11.1963	11.4777	11.6487	11.8881	12.1776	12.9415	13.4878	14.164	14.465	14.5845	8.2636	10.0016	12.147	13.241	13.866	14.4218	14.811	15.1904	15.5787	15.9562	16.3353
Other liquids	Transportati	49-IEO2021.7	quad Btu	0.502	0.4834	0.4683	0.4659	0.4686	0.472	0.4776	0.481	0.4839	0.497	0.4814	0.4912	0.5031	0.5079	0.5129	0.5162	0.5171	0.5186	0.5196	0.521	0.5215
Natural gas	Transportati	49-IEO2021.8	quad Btu	3.0742	3.1692	3.039	3.1945	3.4318	3.5285	3.7114	3.788	4.026	4.1348	4.082	4.3569	4.5313	4.7067	4.8671	5.0797	5.2483	5.4475	5.6494	5.8505	6.0281
Electricity	Transportati	49-IEO2021.9	quad Btu	1.4025	1.4629	1.4613	1.4616	1.4566	1.4192	1.4577	1.5495	1.6237	1.6885	1.5762	1.6943	1.7912	1.8771	1.9595	2.0487	2.1503	2.2684	2.3949	2.5386	2.7032
Total	Transportati	49-IEO2021.:	quad Btu	103.1629	104.9714	106.2922	108.7067	110.9338	113.3851	116.2358	118.4976	120.6542	123.1961	107.7755	114.6184	120.0603	123.1418	125.0838	126.7401	127.9282	128.9258	129.9501	130.896	131.8694
Total OECD		49-IEO2021.11.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	26.9153	26.3488	26.0778	26.0922	26.1224	26.205	26.712	26.6059	26.5573	26.9959	23.3003	24.65	25.0838	25.1888	25.1129	24.9873	24.834	24.6649	24.5069	24.3385	24.1856
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	19.1441	19.4259	19.2134	19.4322	19.9447	20.5474	20.7406	21.14	21.7234	21.8767	19.3697	20.4072	20.9682	21.1174	21.0555	20.9855	20.7845	20.5291	20.2642	19.977	19.678
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	3.3689	3.1635	2.924	2.7406	2.5222	2.3629	2.6572	2.6802	2.7094	2.7484	2.5938	2.698	2.9838	2.9911	2.9944	2.9154	2.9081	2.8781	2.8733	2.8701	2.9182
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0.5348	0.5398	0.5281	0.5144	0.4973	0.469	0.4399	0.4239	0.4144	0.4044	0.3385	0.3564	0.3677	0.3724	0.3726	0.3697	0.3648	0.3601	0.3535	0.3457	0.3369
Jet fuel	Transportati	49-IEO2021.:	quad Btu	6.8294	6.9322	6.9115	7.0082	7.1547	7.4793	7.739	8.0535	8.319	8.4594	4.5589	5.8132	7.1144	7.7394	8.023	8.267	8.4007	8.5261	8.6607	8.7863	8.9159
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.345	0.3283	0.307	0.3063	0.3055	0.3047	0.3012	0.2866	0.2927	0.2931	0.2802	0.2854	0.2907	0.2927	0.2947	0.2955	0.2953	0.2952	0.2951	0.2951	0.2951
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.95	0.9719	0.9623	0.9649	1.079	1.074	1.0776	1.0345	1.1675	1.1591	1.1489	1.2549	1.2562	1.2441	1.2298	1.2486	1.2345	1.2524	1.2819	1.3179	1.3301
Electricity	Transportati	49-IEO2021.:	quad Btu	0.4193	0.4293	0.4308	0.4361	0.4439	0.4515	0.4715	0.4904	0.5087	0.5273	0.4381	0.5007	0.5516	0.5917	0.6285	0.6702	0.7242	0.7867	0.8579	0.9396	1.0318
Total	Transportati	49-IEO2021.2	quad Btu	58.5068	58.1397	57.355	57.4948	58.0696	58.8939	60.1391	60.715	61.6924	62.4643	52.0284	55.9656	58.6164	59.5376	59.7112	59.7392	59.5462	59.2926	59.0935	58.8701	58.6917
United States		49-IEO2021.21.																						
Motor gasoline and E85	Transportati	49-IEO2021.2	quad Btu	16.3337	15.8939	15.8116	16.039	16.2161	16.3203	16.6197	16.5976	16.5976	16.7806	14.8256	15.4799	15.4769	15.4739	15.4155	15.333	15.2273	15.1181	15.0136	14.8994	14.7995
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.2	quad Btu	5.826	5.9997	5.7383	5.8984	6.1587	6.255	6.2022	6.2529	6.5547	6.7788	6.1487	6.2644	6.3173	6.3379	6.3657	6.4308	6.4135	6.3902	6.3504	6.3063	6.2429
Residual fuel oil	Transportati	49-IEO2021.2	quad Btu	0.892	0.7763	0.6705	0.5812	0.4465	0.4634	0.6231	0.6646	0.604	0.531	0.4312	0.493	0.718	0.7108	0.6942	0.6072	0.6069	0.575	0.5689	0.5629	0.6064
Liquefied petroleum gas	Transportati	49-IEO2021.2	quad Btu	0.0075	0.01	0.0071	0.0071	0.0072	0.0072	0.0076	0.0071	0.0067	0.0069	0.0057	0.0061	0.0064	0.0066	0.0067	0.0069	0.0069	0.0069	0.007	0.0071	0.0072
Jet fuel	Transportati	49-IEO2021.2	quad Btu	3.1445	3.1647	3.1177	3.1071	3.1376	3.2805	3.3868	3.442	3.49	3.5487	2.2398	2.9432	3.2603	3.388	3.453	3.5127	3.5314	3.5476	3.5776	3.5994	3.6296
Other liquids	Transportati	49-IEO2021.2	quad Btu	0.1818	0.1754	0.1605	0.1657	0.1711	0.184	0.1749	0.1632	0.1597	0.1529	0.1441	0.1463	0.1478	0.1489	0.1496	0.15	0.1502	0.15	0.1498	0.1497	0.1496
Natural gas	Transportati	49-IEO2021.2	quad Btu	0.7113	0.721	0.718	0.6837	0.7775	0.7664	0.7558	0.7152	0.8105	0.8043	0.7937	0.8746	0.8546	0.8245	0.7946	0.7923	0.7568	0.7601	0.7683	0.7767	0.7739
Electricity	Transportati	49-IEO2021.2	quad Btu	0.0239	0.0245	0.025	0.0269	0.0283	0.0295	0.0308	0.0329	0.0367	0.0425	0.0355	0.0427	0.0487	0.0542	0.0594	0.0646	0.0708	0.0773	0.0839	0.0908	0.0987
Total	Transportati	49-IEO2021.3	quad Btu	27.1206	26.7656	26.2487	26.5091	26.9428	27.3065	27.8008	27.8754	28.26	28.6455	24.6242	26.2502	26.8301	26.9448	26.9388	26.8975	26.7638	26.6253	26.5195	26.3923	26.3077
Canada		49-IEO2021.31.																						
Motor gasoline and E85	Transportati	49-IEO2021.3	quad Btu	1.4161	1.4174	1.4239	1.444	1.4255	1.4394	1.507	1.5269	1.5433	1.5664	1.4843	1.5029	1.5051	1.501	1.4931	1.4812	1.4693	1.4555	1.4417	1.4258	1.41
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.3	quad Btu	0.7931	0.8303	0.8164	0.8297	0.8236	0.7825	0.7318	0.7978	0.8638	0.8549	0.7589	0.801	0.8312	0.8443	0.8434	0.8452	0.8462	0.847	0.8482	0.8502	0.8511
Residual fuel oil	Transportati	49-IEO2021.3	quad Btu	0.0644	0.0483	0.0483	0.0483	0.0402	0.0322	0.0322	0.024	0.024	0.025	0.0224	0.023	0.0236	0.0233	0.0233	0.0231	0.0229	0.0228	0.0227	0.0225	0.0224
Liquefied petroleum gas	Transportati	49-IEO2021.3	quad Btu	0.0108	0.0109	0.0105	0.0105	0.0109	0.0104	0.0102	0.0108	0.0114	0.0091	0.0083	0.0084	0.0085	0.0084	0.0084	0.0083	0.0082	0.0081	0.008	0.0079	0.0078
Jet fuel	Transportati	49-IEO2021.3	quad Btu	0.218	0.221	0.254	0.264	0.258	0.263	0.271	0.293	0.324	0.3272	0.1395	0.1847	0.244	0.2743	0.2904	0.3022	0.3072	0.3116	0.316	0.3206	0.3251
Other liquids	Transportati	49-IEO2021.3	quad Btu	0.0156	0.0117	0.0117	0.0117	0.0098	0.0078	0.0078	0.0058	0.0058	0.0061	0.0054	0.0056	0.0057	0.0057	0.0057	0.0056	0.0056	0.0055	0.0055	0.0055	0.0054
Natural gas	Transportati	49-IEO2021.3	quad Btu	0.1087	0.1077	0.1094	0.1281	0.1511	0.1566	0.1599	0.1412	0.1601	0.1518	0.1496	0.1525	0.1521	0.1502	0.1491	0.1568	0.1652	0.1699	0.177	0.1806	0.1796
Electricity	Transportati	49-IEO2021.3	quad Btu	0.0005	0.0005	0.0005	0.0006	0.0006	0.0007	0.0009	0.0012	0.0017	0.0025	0.0026	0.0032	0.0037	0.004	0.005	0.0066	0.0081	0.0095	0.0112	0.0133	0.0158
Total	Transportati	49-IEO2021.4	quad Btu	2.6272	2.6478	2.6748	2.7369	2.7196	2.6925	2.7208	2.8007	2.9342	2.943	2.571	2.6814	2.7738	2.8113	2.8183	2.8292	2.8326	2.83	2.8303	2.8264	2.8171
Mexico and Other		49-IEO2021.41.																						
Motor gasoline and E85	Transportati	49-IEO2021.4	quad Btu	1.8379	1.9259	1.9705	1.9329	1.9244	1.9538	2.0683	2.0091	1.9562	1.9714	1.5804	1.706	1.7754	1.819	1.8486	1.8729	1.8931	1.9036	1.9173	1.9313	1.9479
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.4	quad Btu	0.963	1.0474	1.074	1.0774	1.0887	1.0726	1.0972	1.0618	1.0262	0.9998	0.8163	0.8805	0.9161	0.9386	0.9508	0.9601	0.9659	0.9671	0.9693	0.97	0.9715
Residual fuel oil	Transportati	49-IEO2021.4	quad Btu	0.0462	0.037	0.0277	0.0277	0.0277	0.0185	0.0185	0.0187	0.0187	0.0195	0.019	0.0194	0.02	0.0202	0.0204	0.0206	0.0206	0.0207	0.0208	0.0209	0.021
Liquefied petroleum gas	Transportati	49-IEO2021.4	quad Btu	0.0103	0.0107	0.0109	0.0101	0.0095	0.0094	0.01	0.0097	0.0093	0.009	0.0065	0.0067	0.0066	0.0062	0.0058	0.0052	0.0047	0.0042	0.0037	0.0033	0.0029
Jet fuel	Transportati	49-IEO2021.4	quad Btu	0.2018	0.2079	0.2178	0.2154	0.2386	0.2621	0.2668	0.2957	0.3196	0.3172	0.1344	0.1832	0.2399	0.2704	0.2894	0.305	0.316	0.3269	0.3377	0.3486	0.3595
Other liquids	Transportati	49-IEO2021.4	quad Btu	0.0038	0.003	0.0023	0.0023	0.0023	0.0015	0.0015	0.0015	0.0015	0.0016	0.0016	0.0016	0.0016	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017
Natural gas	Transportati	49-IEO2021.4	quad Btu	0.0001	0.0003	0.0003	0.0003	0.0003	0.0004	0.0005	0.0006	0.0007	0.0016	0.0023	0.0039	0.0055	0.0069	0.0082	0.0097	0.0111	0.0126	0.0142	0.0158	0.0179
Electricity	Transportati	49-IEO2021.4	quad Btu	0.0004	0.0005	0.0005	0.0005	0.0005	0.0005	0.0006	0.0006	0.0007	0.0008	0.0004	0.0005	0.0006	0.0007	0.0008	0.0009	0.0011	0.0012	0.0014	0.0017	0.002
Total	Transportati	49-IEO2021.5	quad Btu	3.0635	3.2326	3.304	3.2666	3.2919	3.3188	3.4635	3.3977	3.333	3.321	2.5608	2.8019	2.9657	3.0636	3.1257	3.1761	3.2141	3.238	3.2662	3.2933	3.3243
OECD Europe		49-IEO2021.51.																						
Motor gasoline and E85	Transportati	49-IEO2021.5	quad Btu	4.3293	4.1716	3.9319	3.787	3.7323	3.6913	3.691	3.6897	3.7123	3.8586	2.982	3.3802	3.6686	3.7413	3.7381	3.7258	3.7151	3.7036	3.6912	3.6778	3.6611
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.5	quad Btu	9.2927	9.314	9.2923	9.3205	9.5	9.9562	10.2054	10.4178	10.5697	10.5306	9.1172	9.8127	10.2014	10.2683	10.1662	10.0232	9.8465	9.6357	9.4301	9.2124	9.0033
Residual fuel oil	Transportati	49-IEO2021.5	quad Btu	1.7208	1.7208	1.5797	1.5045	1.4199	1.2416	1.3072	1.3453	1.4107	1.4888	1.4551	1.4822	1.5235	1.5333	1.5465	1.5518	1.5463	1.5471	1.5473	1.5486	1.5482
Liquefied petroleum gas	Transportati	49-IEO2021.5	quad Btu	0.1487	0.1582	0.1628	0.165	0.1644	0.1646	0.1664	0.17	0.1752	0.1812	0.1396	0.1615	0.1806	0.1942	0.2038	0.2104	0.2148	0.2189	0.2203	0.2199	0.2176
Jet fuel	Transportati	49-IEO2021.5	quad Btu	2.331	2.4105	2.362	2.3975	2.4778	2.6065	2.6887	2.8546	2.987	3.0841	1.4305	1.7928	2.438	2.7556	2.8785	2.987	3.0603	3.1305	3.1978	3.2655	3.331
Other liquids	Transportati	49-IEO2021.5	quad Btu	0.1093	0.1093	0.1003	0.0955	0.0901	0.0788	0.0832	0.0857	0.0899	0.0949	0.0927	0.0944	0.097	0.0977	0.0985	0.0989	0.0985	0.0986	0.0986	0.0987	0.0986
Natural gas	Transportati	49-IEO2021.5	quad Btu	0.094	0.1048	0.0942	0.1091	0.1046	0.1027	0.1094	0.1216	0.1382	0.1405	0.1432	0.1563	0.17	0.183	0.1934	0.2004	0.2079	0.2121	0.2199	0.2376	0.2508
Electricity	Transportati	49-IEO2021.5	quad Btu	0.2491	0.2567	0.2507	0.2511	0.2537	0.2542	0.2634	0.2758	0.288	0.2982	0.2508	0.2858	0.3143	0.3409	0.3669	0.397	0.4381	0.4862	0.542	0.6067	0.6801
Total	Transportati	49-IEO2021.6	quad Btu	18.2748	18.2458	17.7739	17.6302	17.7427	18.0959	18.5148	18.9603	19.371	19.6768	15.6111	17.1659	18.5934	19.1144	19.192	19.1944	19.1275	19.0326	18.9472	18.8671	18.7906

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Japan		49-IEO2021.61.																						
Motor gasoline and E85	Transportati	49-IEO2021.6	quad Btu	1.8959	1.8484	1.8554	1.8	1.7465	1.7141	1.7139	1.6644	1.62	1.6463	1.3645	1.4849	1.5549	1.5499	1.516	1.4753	1.4337	1.3908	1.3487	1.3067	1.2657
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.6	quad Btu	1.0538	0.9971	1.005	0.9878	1.0056	0.9985	0.9977	0.9885	0.9787	0.9856	0.8803	0.9431	0.97	0.9728	0.9643	0.9559	0.9453	0.9317	0.9192	0.906	0.893
Residual fuel oil	Transportati	49-IEO2021.6	quad Btu	0.2485	0.2041	0.2307	0.2219	0.2307	0.2395	0.2484	0.2208	0.256	0.2689	0.2607	0.2674	0.2747	0.2768	0.2797	0.281	0.2807	0.2814	0.282	0.2829	0.2842
Liquefied petroleum gas	Transportati	49-IEO2021.6	quad Btu	0.0069	0.0064	0.0061	0.0058	0.0056	0.0053	0.0049	0.0046	0.0044	0.0044	0.0033	0.0033	0.0033	0.003	0.0027	0.0024	0.0021	0.0019	0.0016	0.0014	0.0012
Jet fuel	Transportati	49-IEO2021.6	quad Btu	0.4173	0.4026	0.411	0.4536	0.4564	0.4598	0.4681	0.4813	0.4826	0.4776	0.2716	0.3128	0.3897	0.4317	0.4529	0.4693	0.4774	0.4841	0.4897	0.4943	0.4977
Other liquids	Transportati	49-IEO2021.6	quad Btu	0.0315	0.0259	0.0293	0.0281	0.0293	0.0304	0.0315	0.028	0.0325	0.0341	0.0331	0.0339	0.0349	0.0351	0.0355	0.0357	0.0356	0.0357	0.0358	0.0359	0.0361
Natural gas	Transportati	49-IEO2021.6	quad Btu	0	0.0001	0.0003	0.0005	0.0005	0.0005	0.0005	0.0006	0.0007	0.0012	0.0015	0.0022	0.003	0.0039	0.0048	0.0057	0.0066	0.0076	0.0086	0.0096	0.01
Electricity	Transportati	49-IEO2021.6	quad Btu	0.0978	0.0965	0.0972	0.098	0.0962	0.0975	0.0986	0.1002	0.1009	0.1021	0.0759	0.0904	0.1027	0.1074	0.1094	0.111	0.1127	0.1151	0.118	0.1216	0.1258
Total	Transportati	49-IEO2021.7	quad Btu	3.7517	3.581	3.6349	3.5956	3.5707	3.5454	3.5636	3.4884	3.4758	3.5201	2.8909	3.1381	3.3331	3.3808	3.3653	3.3364	3.2942	3.2483	3.2037	3.1583	3.1136
South Korea		49-IEO2021.71.																						
Motor gasoline and E85	Transportati	49-IEO2021.7	quad Btu	0.3697	0.3658	0.3609	0.3784	0.3802	0.3898	0.4021	0.4067	0.412	0.447	0.4385	0.4361	0.4312	0.4266	0.422	0.4177	0.4136	0.4102	0.4083	0.4075	0.407
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.7	quad Btu	0.6869	0.6779	0.6988	0.7286	0.752	0.8306	0.8516	0.9026	0.9476	0.947	0.9011	0.9304	0.9368	0.9421	0.938	0.9303	0.9182	0.9024	0.886	0.8679	0.8497
Residual fuel oil	Transportati	49-IEO2021.7	quad Btu	0.36	0.34	0.33	0.32	0.32	0.34	0.4	0.3792	0.3591	0.3787	0.3693	0.3758	0.3863	0.3885	0.3917	0.393	0.3918	0.3923	0.3926	0.3932	0.3965
Liquefied petroleum gas	Transportati	49-IEO2021.7	quad Btu	0.3381	0.3309	0.3172	0.3024	0.2858	0.2578	0.2261	0.2068	0.1924	0.1804	0.1629	0.1576	0.1498	0.1415	0.1329	0.1245	0.1162	0.1085	0.1014	0.095	0.0894
Jet fuel	Transportati	49-IEO2021.7	quad Btu	0.2207	0.2202	0.2334	0.2363	0.2512	0.2661	0.2848	0.2934	0.3071	0.304	0.1723	0.1984	0.2477	0.2746	0.2882	0.2988	0.3041	0.3085	0.3123	0.3154	0.3178
Other liquids	Transportati	49-IEO2021.7	quad Btu	0	0	0	0	0	0	0	0	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001
Natural gas	Transportati	49-IEO2021.7	quad Btu	0.0253	0.0282	0.0307	0.033	0.0354	0.0377	0.0401	0.0431	0.0428	0.0422	0.0401	0.0454	0.0499	0.0536	0.0569	0.0599	0.0622	0.0645	0.0668	0.0692	0.0685
Electricity	Transportati	49-IEO2021.7	quad Btu	0.0191	0.0222	0.0263	0.0267	0.029	0.0311	0.039	0.0402	0.0401	0.0401	0.0357	0.0383	0.0399	0.0407	0.0414	0.0421	0.0431	0.0441	0.0451	0.0463	0.0473
Total	Transportati	49-IEO2021.8	quad Btu	2.0198	1.9852	1.9973	2.0255	2.0536	2.1531	2.2437	2.2721	2.3013	2.3396	2.12	2.1822	2.2417	2.2678	2.2714	2.2664	2.2494	2.2307	2.2127	2.1945	2.1764
Australia and New Zealand		49-IEO2021.81.																						
Motor gasoline and E85	Transportati	49-IEO2021.8	quad Btu	0.7327	0.7257	0.7235	0.7108	0.6976	0.6964	0.71	0.7115	0.7158	0.7257	0.625	0.6599	0.6717	0.6772	0.6795	0.6814	0.682	0.683	0.6862	0.69	0.6944
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.8	quad Btu	0.5286	0.5596	0.5886	0.5899	0.6162	0.6521	0.6547	0.7186	0.7826	0.7802	0.7473	0.775	0.7953	0.8135	0.8269	0.8399	0.8489	0.855	0.8609	0.8643	0.8665
Residual fuel oil	Transportati	49-IEO2021.8	quad Btu	0.0371	0.0371	0.0371	0.0371	0.0371	0.0278	0.0278	0.0277	0.0369	0.0366	0.036	0.0372	0.0378	0.0382	0.0386	0.0388	0.0388	0.039	0.0391	0.0392	0.0397
Liquefied petroleum gas	Transportati	49-IEO2021.8	quad Btu	0.0125	0.0128	0.0134	0.0134	0.014	0.0144	0.0146	0.0148	0.015	0.0134	0.0123	0.0126	0.0125	0.0124	0.0122	0.012	0.0118	0.0116	0.0114	0.0111	0.0109
Jet fuel	Transportati	49-IEO2021.8	quad Btu	0.2962	0.3053	0.3156	0.3342	0.3351	0.3412	0.3728	0.3935	0.4085	0.4005	0.171	0.1982	0.2949	0.3447	0.3706	0.3919	0.4044	0.4168	0.4295	0.4426	0.4552
Other liquids	Transportati	49-IEO2021.8	quad Btu	0.0029	0.0029	0.0029	0.0029	0.0029	0.0022	0.0022	0.0023	0.0032	0.0033	0.0032	0.0034	0.0034	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0035	0.0036
Natural gas	Transportati	49-IEO2021.8	quad Btu	0.0107	0.0098	0.0094	0.0102	0.0096	0.0096	0.0113	0.0123	0.0144	0.0175	0.0184	0.0199	0.0212	0.0219	0.0228	0.0238	0.0246	0.0256	0.027	0.0282	0.0296
Electricity	Transportati	49-IEO2021.8	quad Btu	0.0285	0.0286	0.0306	0.0324	0.0357	0.0379	0.0384	0.0397	0.0406	0.0411	0.0372	0.0397	0.0417	0.0436	0.0456	0.048	0.0504	0.0533	0.0562	0.0592	0.0622
Total	Transportati	49-IEO2021.9	quad Btu	1.6493	1.6818	1.7213	1.731	1.7482	1.7816	1.8319	1.9204	2.0171	2.0182	1.6504	1.7459	1.8785	1.955	1.9998	2.0394	2.0645	2.0878	2.1138	2.1382	2.162
Total Non-OECD		49-IEO2021.91.																						
Motor gasoline and E85	Transportati	49-IEO2021.9	quad Btu	15.3345	16.1779	17.1065	18.4671	19.2638	19.9246	20.5637	21.0332	21.5427	22.6323	21.1805	22.1337	23.0224	23.7927	24.4751	25.1058	25.6722	26.1761	26.6667	27.1318	27.5757
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.9	quad Btu	16.7543	17.7007	18.8224	19.3061	19.8042	20.204	20.6712	21.1666	21.6196	21.8107	20.9442	22.0535	22.7183	23.3597	23.8285	24.2483	24.5954	24.8464	25.095	25.2984	25.4959
Residual fuel oil	Transportati	49-IEO2021.9	quad Btu	4.793	4.875	4.8492	4.9922	5.0928	5.1488	5.1368	5.2691	5.2926	5.6099	5.4923	5.5964	5.7568	5.7959	5.8494	5.8759	5.8619	5.8699	5.8756	5.9	5.9266
Liquefied petroleum gas	Transportati	49-IEO2021.9	quad Btu	0.1429	0.1465	0.1535	0.1519	0.1519	0.1621	0.1799	0.1962	0.196	0.213	0.1529	0.1793	0.1867	0.1911	0.1899	0.1858	0.1806	0.1763	0.1722	0.1684	0.1645
Jet fuel	Transportati	49-IEO2021.9	quad Btu	4.367	4.5456	4.7372	4.8799	5.0229	5.4622	5.7488	6.1105	6.1461	6.1251	3.7047	4.1884	5.0326	5.5016	5.8431	6.1548	6.4103	6.6643	6.918	7.1699	7.4193
Other liquids	Transportati	49-IEO2021.9	quad Btu	0.157	0.1552	0.1613	0.1596	0.1631	0.1672	0.1764	0.1945	0.1913	0.2039	0.2012	0.2058	0.2124	0.2152	0.2182	0.2206	0.2218	0.2234	0.2245	0.2258	0.2263
Natural gas	Transportati	49-IEO2021.9	quad Btu	2.1241	2.1973	2.0767	2.2296	2.3528	2.4545	2.6338	2.7536	2.8585	2.9757	2.9331	3.102	3.2751	3.4626	3.6374	3.8311	4.0137	4.1951	4.3675	4.5326	4.698
Electricity	Transportati	49-IEO2021.9	quad Btu	0.9833	1.0335	1.0305	1.0255	1.0127	0.9677	0.9862	1.0591	1.1151	1.1612	1.1381	1.1936	1.2397	1.2854	1.331	1.3784	1.4261	1.4817	1.537	1.599	1.6713
Total	Transportati	49-IEO2021.1	quad Btu	44.6561	46.8316	48.9372	51.2119	52.8642	54.4912	56.0967	57.7827	58.9618	60.7317	55.747	58.6528	61.4439	63.6043	65.3726	67.0009	68.382	69.6331	70.8566	72.0259	73.1777
Russia		49-IEO2021.101.																						
Motor gasoline and E85	Transportati	49-IEO2021.1	quad Btu	1.3706	1.4168	1.483	1.5465	1.5768	1.5309	1.52	1.4691	1.4207	1.4494	1.3861	1.3991	1.3978	1.3967	1.3968	1.3974	1.3982	1.398	1.3981	1.3984	1.3977
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.1	quad Btu	0.7094	0.7295	0.6642	0.7846	0.9504	0.964	1.0837	1.1324	1.1791	1.1847	1.1164	1.159	1.1764	1.1932	1.2046	1.2101	1.2099	1.206	1.2035	1.199	1.1946
Residual fuel oil	Transportati	49-IEO2021.1	quad Btu	0.0599	0.0999	0.0499	0.2197	0.2097	0.1301	0.08	0.101	0.0911	0.0955	0.0933	0.0949	0.0973	0.0978	0.0986	0.0987	0.0982	0.098	0.0978	0.0976	0.0973
Liquefied petroleum gas	Transportati	49-IEO2021.1	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jet fuel	Transportati	49-IEO2021.1	quad Btu	0.5005	0.5415	0.5592	0.5319	0.5009	0.4433	0.4277	0.4417	0.4628	0.459	0.3696	0.3914	0.4137	0.43	0.4436	0.4562	0.4631	0.4698	0.476	0.4826	0.4874
Other liquids	Transportati	49-IEO2021.1	quad Btu	0.0001	0.0001	0.0001	0.0003	0.0003	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Natural gas	Transportati	49-IEO2021.1	quad Btu	1.4678	1.4067	1.2252	1.2117	1.217	1.2449	1.349	1.3798	1.412	1.4595	1.465	1.5245	1.5633	1.6022	1.6291	1.6718	1.7048	1.7271	1.7494	1.7724	1.7948
Electricity	Transportati	49-IEO2021.1	quad Btu	0.2109	0.2236	0.2341	0.2313	0.2406	0.241	0.2416	0.2527	0.2585	0.2594	0.2373	0.2393	0.2441	0.2499	0.2531	0.2542	0.254	0.2537	0.2534	0.2523	0.2509
Total	Transportati	49-IEO2021.1	quad Btu	4.3192	4.4181	4.2156	4.5259	4.6957	4.5544	4.7021	4.7768	4.8243	4.9078	4.6678	4.8083	4.8927	4.9701	5.0258	5.0887	5.1284	5.1527	5.1784	5.2023	5.2228
Other Non-OECD Europe and Eurasia		49-IEO2021.111.																						
Motor gasoline and E85	Transportati	49-IEO2021.1	quad Btu	0.7812	0.7888	0.7769	0.7566	0.7618	0.7541	0.7822	0.7558	0.732	0.7458	0.7247	0.7406	0.7538	0.7647	0.7753	0.7875	0.8003	0.8131	0.8266	0.8405	0.8545
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.1	quad Btu	0.865	0.9279	0.9276	0.9271	0.9511	0.9431	0.9931	1.0845	1.1742	1.1549	1.1418	1.1808	1.2192	1.246	1.2606	1.272	1.277	1.2759	1.2761	1.2754	1.2768
Residual fuel oil	Transportati	49-IEO2021.1	quad Btu	0.254	0.2631	0.2449	0.2268	0.2177	0.218	0.2179	0.2467	0.2469	0.2622	0.2573	0.2627	0.2708	0.2735	0.2768	0.2787	0.2787	0.2799	0.2811	0.2826	0.2804
Liquefied petroleum gas	Transportati	49-IEO2021.1	quad Btu	0.003	0.0032	0.0033	0.0036	0.0035	0.0036	0.0035	0.0034	0.0032	0.0031	0.0061	0.0095	0.0126	0.0155	0.0181	0.0202	0.0221	0.0251	0.0278	0.0303	0.0324
Jet fuel	Transportati	49-IEO2021.1	quad Btu	0.1767	0.166	0.1602	0.1219	0.1275	0.1256	0.1401	0.1627	0.1689	0.1699	0.1165	0.1287	0.1466	0.1566	0.1623	0.1674	0.1704	0.1734	0.1762	0.179	0.1815
Other liquids	Transportati	49-IEO2021.1	quad Btu	0.026	0.0269	0.0251	0.0232	0.0223	0.0223	0.0223	0.0253	0.0253	0.0269	0.0264	0.0269	0.0277	0.028	0.0283	0.0285	0.0285	0.0287	0.0288	0.0289	0.0287
Natural gas	Transportati	49-IEO2021.1	quad Btu	0.2806	0.3146	0.2515	0.2814	0.2726	0.2379	0.2365	0.2522	0.2225	0.2469	0.236	0.2443	0.2475	0.2531	0.257	0.2682	0.2708	0.2772	0.273	0.269	0.2743
Electricity	Transportati	49-IEO2021.1	quad Btu	0.0677	0.0743	0.0741	0.0725	0.0681	0.0642	0.0616	0.0611	0.0624	0.0609	0.055	0.0562	0.0568	0.0571	0.0569	0.0566	0.0567	0.0565	0.0564	0.0563	0.056
Total	Transportati	49-IEO2021.1	quad Btu	2.4542	2.5648	2.4635	2.413	2.4246	2.3689	2.4572	2.5918	2.6355	2.6705	2.5637	2.6497	2.7351	2.7945	2.8353	2.8792	2.9045	2.9298	2.946	2.962	2.9846

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
China		49-IEO2021.121.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	3.3493	3.7276	4.0282	4.5483	4.8053	5.0318	5.2494	5.5234	5.7794	6.2653	6.4284	6.8014	7.1825	7.4804	7.7396	7.966	8.1471	8.2777	8.3823	8.451	8.4803
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	4.1361	4.542	5.0982	5.1479	5.1962	5.2748	5.1576	5.1971	5.235	5.4959	5.6299	5.8625	5.9218	5.9581	5.9645	5.9621	5.9427	5.9027	5.8592	5.8048	5.7419
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.6383	0.6295	0.6645	0.6732	0.6732	0.6287	0.6729	0.72	0.6668	0.7181	0.7107	0.7257	0.7465	0.7524	0.7596	0.7652	0.7664	0.7695	0.7705	0.7733	0.7741
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0.0015	0.002	0.0037	0.0059	0.0087	0.0123	0.0176	0.0227	0.028	0.0364	0.0138	0.0362	0.0369	0.0371	0.0372	0.037	0.0367	0.0361	0.0353	0.0342	0.0327
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.85	0.8798	0.959	1.0613	1.1204	1.3968	1.5374	1.6304	1.4888	1.5044	1.2314	1.3044	1.3909	1.438	1.5011	1.572	1.6368	1.7002	1.7637	1.826	1.8883
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0917	0.0906	0.096	0.0985	0.1027	0.1076	0.1204	0.1337	0.1296	0.1387	0.1372	0.1405	0.1452	0.1474	0.1496	0.1516	0.1527	0.154	0.1549	0.1559	0.1564
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0829	0.1245	0.1862	0.2804	0.3795	0.4649	0.5101	0.5594	0.6097	0.6308	0.6608	0.7133	0.7887	0.8655	0.9436	1.0236	1.1074	1.1904	1.2769	1.3627	1.4529
Electricity	Transportati	49-IEO2021.:	quad Btu	0.538	0.562	0.5496	0.5474	0.5262	0.4902	0.512	0.5708	0.6166	0.6605	0.6762	0.7153	0.7482	0.7803	0.8146	0.8531	0.8923	0.9372	0.9803	1.0289	1.086
Total	Transportati	49-IEO2021.:	quad Btu	9.6878	10.558	11.5854	12.363	12.8121	13.4071	13.7775	14.3575	14.554	15.45	15.4884	16.2992	16.9607	17.4591	17.9099	18.3306	18.6821	18.9679	19.2231	19.4366	19.6126
India		49-IEO2021.131.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	0.6412	0.6623	0.7004	0.7624	0.8182	0.94	1.0484	1.1321	1.2108	1.295	1.133	1.1921	1.3044	1.4316	1.5374	1.632	1.7321	1.8406	1.9595	2.0921	2.2385
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	1.8359	2.0291	2.1886	2.182	2.1775	2.3419	2.488	2.5925	2.6982	2.7943	2.5434	2.8428	3.0453	3.271	3.4772	3.6712	3.8566	4.0359	4.2204	4.3987	4.5799
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.09	0.08	0.08	0.07	0.07	0.0699	0.08	0.0893	0.0991	0.1022	0.1016	0.1054	0.1085	0.1106	0.1129	0.1146	0.1159	0.1175	0.1188	0.1204	0.1217
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0.0437	0.0474	0.0511	0.0531	0.0551	0.0578	0.0547	0.0564	0.0581	0.0613	0.0387	0.0367	0.0414	0.0446	0.0437	0.0406	0.0374	0.0341	0.0316	0.0294	0.0279
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.2287	0.2455	0.2391	0.2453	0.2556	0.2737	0.3057	0.3342	0.3698	0.3598	0.1733	0.2066	0.279	0.3174	0.3458	0.3723	0.3978	0.4243	0.4519	0.4804	0.5097
Other liquids	Transportati	49-IEO2021.:	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0784	0.131	0.1785	0.2116	0.2375	0.2591	0.2745	0.2962	0.3197	0.3291	0.2581	0.2768	0.3016	0.3355	0.3675	0.3918	0.4192	0.4506	0.4835	0.5165	0.5497
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0952	0.1023	0.1019	0.104	0.1075	0.1038	0.0996	0.1031	0.1028	0.1045	0.0988	0.1091	0.1146	0.1208	0.1283	0.1361	0.1434	0.1532	0.1646	0.1776	0.1927
Total	Transportati	49-IEO2021.:	quad Btu	3.0131	3.2976	3.5397	3.6284	3.7213	4.0464	4.3508	4.6039	4.8585	5.0462	4.3469	4.7695	5.1948	5.6315	6.0127	6.3586	6.7024	7.0562	7.4302	7.8151	8.2202
Other Non-OECD Asia		49-IEO2021.141.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	2.3584	2.5488	2.6808	2.8788	3.0181	3.0761	3.2994	3.3719	3.4465	3.6478	3.5748	3.728	3.8631	3.9927	4.1234	4.2634	4.4005	4.5395	4.6902	4.8406	4.9927
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	2.5955	2.6443	2.7383	2.7393	2.8217	2.8689	3.1634	3.3196	3.4416	3.4333	3.4259	3.588	3.703	3.8181	3.8866	3.9444	3.9878	4.0097	4.0273	4.0375	4.0454
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	2.2211	2.2112	2.1414	2.1614	2.1016	2.2105	2.3404	2.3432	2.3816	2.5276	2.4695	2.5179	2.593	2.6121	2.6383	2.6512	2.6457	2.6513	2.6565	2.6772	2.6826
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0.0117	0.0161	0.0197	0.0214	0.0226	0.023	0.0239	0.024	0.0242	0.0239	0.0236	0.0243	0.0247	0.025	0.0252	0.0255	0.0252	0.0245	0.0235	0.0223	0.0209
Jet fuel	Transportati	49-IEO2021.:	quad Btu	1.1338	1.2109	1.2745	1.371	1.3925	1.4633	1.5692	1.6497	1.731	1.7386	0.8743	0.9922	1.3326	1.5143	1.6346	1.7392	1.8236	1.9078	1.991	2.0727	2.1523
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0089	0.0088	0.0086	0.0086	0.0084	0.0088	0.0094	0.0094	0.0095	0.0101	0.0099	0.0101	0.0104	0.0104	0.0105	0.0106	0.0106	0.0106	0.0106	0.0107	0.0107
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0502	0.0646	0.073	0.0783	0.0807	0.0817	0.086	0.0885	0.0934	0.1041	0.1017	0.1171	0.131	0.1441	0.1568	0.1695	0.1819	0.1944	0.2076	0.2082	0.2222
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0089	0.0086	0.0083	0.008	0.0081	0.0082	0.0081	0.0081	0.0085	0.0087	0.0068	0.0076	0.0079	0.008	0.008	0.0081	0.0084	0.0088	0.0092	0.0099	0.0106
Total	Transportati	49-IEO2021.:	quad Btu	8.3886	8.7134	8.9446	9.2668	9.4537	9.7406	10.4998	10.8143	11.1362	11.494	10.4864	10.9852	11.6656	12.1247	12.4834	12.812	13.0836	13.3465	13.6159	13.8789	14.1374
Middle East		49-IEO2021.151.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	2.4893	2.5455	2.6941	2.9315	2.9874	3.083	3.1183	3.1792	3.2668	3.3564	3.1439	3.1327	3.1225	3.1032	3.0816	3.0592	3.0311	2.9996	2.9701	2.9427	2.92
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	2.1454	2.2164	2.3493	2.3058	2.3917	2.3925	2.3169	2.2895	2.2636	2.171	2.0252	2.1092	2.1636	2.2149	2.2446	2.2722	2.2937	2.3028	2.3142	2.321	2.3279
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.868	0.9178	0.9378	0.9677	1.1373	1.2368	1.1572	1.123	1.1918	1.251	1.2165	1.2345	1.2645	1.2668	1.2725	1.2712	1.2602	1.2535	1.2472	1.2412	1.2595
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0	0	0	0	0	0	0	0.0016	0.0032	0.0048	0.0046	0.0048	0.0049	0.005	0.0053	0.0056	0.0058	0.006	0.0062	0.0063	0.0064
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.5543	0.5689	0.5953	0.5941	0.6425	0.7799	0.8	0.8751	0.8631	0.8356	0.4459	0.5149	0.6462	0.7251	0.7752	0.8142	0.8444	0.8741	0.9039	0.9325	0.9615
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.002	0.0022	0.0022	0.0023	0.0027	0.0029	0.0027	0.0026	0.0028	0.0029	0.0029	0.0029	0.003	0.003	0.003	0.003	0.003	0.0029	0.0029	0.0029	0.003
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0523	0.0524	0.0556	0.0586	0.0604	0.0604	0.0619	0.0675	0.0752	0.0836	0.0871	0.0931	0.1037	0.1169	0.131	0.1459	0.1616	0.1792	0.1966	0.2151	0.2083
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0022	0.0024	0.0025	0.0026	0.0026	0.0026	0.0025	0.0028	0.0043	0.0057	0.0045	0.0054	0.0056	0.0056	0.0052	0.0048	0.0048	0.0048	0.0048	0.0047	0.0045
Total	Transportati	49-IEO2021.:	quad Btu	6.1135	6.3056	6.6368	6.8625	7.2247	7.5581	7.4595	7.5413	7.6707	7.7109	6.9306	7.0974	7.314	7.4404	7.5183	7.5761	7.6047	7.623	7.6458	7.6664	7.6911
Africa		49-IEO2021.161.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	1.5819	1.6725	1.7188	1.9591	2.0778	2.1365	2.1724	2.2097	2.2655	2.3064	1.8952	2.0448	2.173	2.294	2.4077	2.5186	2.625	2.7233	2.8116	2.8972	2.9814
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	1.9465	2.0021	2.1294	2.366	2.4178	2.4622	2.5424	2.6185	2.6925	2.6711	2.4665	2.5234	2.595	2.6733	2.7428	2.8094	2.8686	2.9186	2.9672	3.0126	3.0607
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.1694	0.1516	0.1694	0.1516	0.1516	0.1427	0.1159	0.125	0.134	0.1403	0.1381	0.1407	0.1446	0.1462	0.148	0.1492	0.1495	0.1503	0.1511	0.1521	0.1529
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0.083	0.0778	0.0756	0.0679	0.062	0.0655	0.0801	0.088	0.0794	0.0834	0.066	0.0679	0.0663	0.0639	0.0605	0.0569	0.0535	0.0504	0.0478	0.0459	0.0442
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.4389	0.432	0.4277	0.4179	0.4251	0.4186	0.4235	0.4574	0.4863	0.4891	0.215	0.2851	0.3696	0.4171	0.4458	0.4701	0.4877	0.5051	0.5228	0.541	0.5595
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0206	0.0185	0.0206	0.0185	0.0185	0.0174	0.0141	0.0152	0.0163	0.0171	0.0168	0.0171	0.0176	0.0178	0.018	0.0182	0.0182	0.0183	0.0184	0.0185	0.0186
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0435	0.0426	0.0392	0.0288	0.0272	0.0305	0.0414	0.044	0.0394	0.0392	0.0396	0.0426	0.0455	0.0479	0.0504	0.0531	0.0564	0.0598	0.0629	0.0663	0.0699
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0349	0.0343	0.0338	0.0333	0.0326	0.0321	0.0323	0.0322	0.0325	0.0326	0.0313	0.0314	0.0318	0.0323	0.0328	0.0332	0.0336	0.0342	0.0346	0.0352	0.0357
Total	Transportati	49-IEO2021.:	quad Btu	4.3186	4.4313	4.6145	5.043	5.2126	5.3054	5.4221	5.59	5.7458	5.7791	4.8684	5.153	5.4433	5.6926	5.9061	6.1085	6.2925	6.46	6.6164	6.7688	6.9229
Brazil		49-IEO2021.171.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	1.5093	1.5652	1.6593	1.77	1.8756	1.9191	1.8947	1.9172	1.9538	2.0468	1.8735	1.9534	2.0014	2.0397	2.0673	2.0863	2.098	2.1062	2.115	2.1241	2.135
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	1.3918	1.4773	1.5637	1.6604	1.6759	1.6961	1.6503	1.6544	1.6582	1.6146	1.5527	1.648	1.7031	1.747	1.779	1.8084	1.8324	1.8474	1.8604	1.869	1.877
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.1677	0.1973	0.1776	0.1579	0.1677	0.1775	0.1578	0.1669	0.1275	0.1363	0.1367	0.1381	0.1431	0.1444	0.1461	0.1475	0.1478	0.1486	0.1494	0.1503	0.151
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.2237	0.2482	0.2594	0.2589	0.2672	0.263	0.2401	0.2378	0.2548	0.2511	0.1344	0.1723	0.2077	0.2276	0.241	0.2537	0.265	0.2762	0.2874	0.2988	0.3103
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0023	0.0027	0.0024	0.0021	0.0023	0.0024	0.0021	0.0023	0.0017	0.0019	0.0019	0.0019	0.0019	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.0021
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0203	0.0133	0.0189	0.0334	0.0369	0.0332	0.0422	0.0303	0.0553	0.0472	0.0494	0.0533	0.0554	0.0578	0.0608	0.0642	0.0667	0.0695	0.0688	0.0716	0.0727
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0244	0.0249	0.0253	0.0257	0.026	0.0245	0.0272	0.027	0.0282	0.0277	0.0275	0.0285	0.0296	0.0303	0.0309	0.0314	0.0319	0.0324	0.0329	0.0335	0.034

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Other Non-OECD Americas		49-IEO2021.181.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	1.2533	1.2504	1.3649	1.314	1.3429	1.4532	1.479	1.4748	1.4672	1.5195	1.0208	1.1417	1.224	1.2896	1.3459	1.3954	1.4398	1.4781	1.5133	1.5453	1.5756
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	1.1287	1.132	1.1632	1.1929	1.2221	1.2606	1.2757	1.2782	1.2772	1.2909	1.0424	1.1398	1.191	1.2382	1.2687	1.2985	1.3266	1.3474	1.3667	1.3805	1.3918
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.3246	0.3246	0.3837	0.364	0.364	0.3345	0.3148	0.3539	0.3537	0.3767	0.3688	0.3766	0.3884	0.3921	0.3968	0.3996	0.3997	0.4014	0.4032	0.4054	0.4072
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.2604	0.2529	0.2627	0.2777	0.2912	0.2979	0.3051	0.3215	0.3206	0.3176	0.1443	0.1929	0.2463	0.2755	0.2939	0.3096	0.3215	0.3333	0.3451	0.357	0.3689
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0054	0.0054	0.0063	0.006	0.006	0.0055	0.0052	0.0059	0.0059	0.0062	0.0061	0.0062	0.0064	0.0065	0.0066	0.0066	0.0066	0.0066	0.0067	0.0067	0.0067
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0482	0.0477	0.0487	0.0455	0.0409	0.0418	0.0321	0.0356	0.0314	0.0353	0.0355	0.0369	0.0382	0.0395	0.0412	0.043	0.0449	0.0469	0.0488	0.0509	0.053
Electricity	Transportati	49-IEO2021.:	quad Btu	0.001	0.0009	0.0008	0.0008	0.0009	0.0011	0.0012	0.0013	0.0013	0.0013	0.0008	0.001	0.0011	0.0011	0.0011	0.001	0.0009	0.0009	0.0008	0.0008	0.0007
Total	Transportati	49-IEO2021.:	quad Btu	3.0216	3.0139	3.2304	3.2008	3.268	3.3947	3.4132	3.4712	3.4573	3.5474	2.6187	2.8952	3.0955	3.2425	3.3541	3.4537	3.54	3.6146	3.6847	3.7465	3.804

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Growth (2020-2050)
Total World		49-IEO2021.1.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	52.0392	52.2957	52.5448	52.8003	53.0457	53.3172	53.6185	53.9323	54.2766	54.6022	54.9102	55.2032	55.4676	55.7053	55.9198	56.0825	56.2564	56.3925	56.5346	56.6448	0.80%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	45.0799	44.9665	44.8366	44.7824	44.7385	44.7262	44.6876	44.6483	44.6738	44.6812	44.7876	44.9048	45.0924	45.2636	45.4916	45.6495	45.8947	46.1249	46.3798	46.5531	0.50%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	8.8575	8.8727	8.8925	8.9019	8.9083	8.8914	8.8696	8.8179	8.7788	8.6847	8.7436	8.6663	8.6112	8.5184	8.4719	8.3393	8.2149	8.1162	8.0133	7.861	-0.10%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.4945	0.4857	0.4756	0.4643	0.4518	0.4403	0.4279	0.4153	0.403	0.3908	0.3795	0.3685	0.3574	0.3461	0.3344	0.3223	0.3099	0.297	0.284	0.2708	-2.00%
Jet fuel	Transportati	49-IEO2021.	quad Btu	16.7193	17.1077	17.4913	17.8697	18.244	18.5964	18.9385	19.2877	19.6474	20.0171	20.3857	20.7686	21.1521	21.5486	21.9491	22.3513	22.7529	23.1543	23.5726	24.0046	3.60%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.5246	0.5251	0.5257	0.5257	0.5254	0.5235	0.5229	0.5202	0.5176	0.5138	0.5122	0.5089	0.5056	0.5014	0.4979	0.4922	0.4864	0.481	0.4792	0.4723	-0.10%
Natural gas	Transportati	49-IEO2021.	quad Btu	6.2345	6.4667	6.7082	6.9688	7.2495	7.5262	7.7964	8.1031	8.4101	8.7541	9.0074	9.3629	9.7176	10.0955	10.4648	10.859	11.254	11.6359	11.9858	12.4581	3.80%
Electricity	Transportati	49-IEO2021.	quad Btu	2.8803	3.0742	3.2871	3.5183	3.7733	4.0178	4.2569	4.5058	4.7578	5.0157	5.2802	5.5426	5.8065	6.0697	6.3282	6.5907	6.8491	7.1082	7.3652	7.6205	5.40%
Total	Transportati	49-IEO2021.	quad Btu	132.8296	133.7943	134.7618	135.8315	136.9364	138.039	139.1182	140.2306	141.4651	142.6596	144.0065	145.3257	146.7103	148.0487	149.4577	150.6867	152.0183	153.31	154.6144	155.8852	1.20%
Total OECD		49-IEO2021.11.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	24.0492	23.9161	23.8014	23.7006	23.6032	23.5109	23.4236	23.3442	23.2901	23.2221	23.1635	23.118	23.0814	23.0472	23.0154	22.9731	22.937	22.8975	22.8643	22.8238	-0.10%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	19.4155	19.1437	18.8868	18.6749	18.4805	18.3064	18.1355	17.9842	17.8575	17.745	17.6665	17.6251	17.605	17.5895	17.5887	17.5817	17.6077	17.6371	17.6795	17.6985	-0.30%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	2.9012	2.9041	2.9082	2.9098	2.9106	2.9015	2.8962	2.8783	2.8695	2.8282	2.8561	2.8172	2.8133	2.7817	2.779	2.7385	2.7042	2.6775	2.6465	2.6099	0.00%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.335	0.3328	0.3309	0.3289	0.3265	0.3251	0.3223	0.3183	0.3134	0.3071	0.3006	0.2933	0.2852	0.2766	0.2672	0.2574	0.2471	0.2363	0.2252	0.2139	-1.50%
Jet fuel	Transportati	49-IEO2021.	quad Btu	9.0494	9.1865	9.3246	9.4594	9.5925	9.7109	9.8211	9.9373	10.0621	10.1955	10.3325	10.4812	10.6337	10.7933	10.9523	11.1148	11.2742	11.4329	11.6024	11.7804	3.20%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.2966	0.2968	0.2971	0.2974	0.2976	0.297	0.2966	0.2959	0.2953	0.2941	0.2949	0.2942	0.294	0.2931	0.2925	0.291	0.2895	0.2884	0.2865	0.2845	0.10%
Natural gas	Transportati	49-IEO2021.	quad Btu	1.3512	1.3953	1.4386	1.488	1.5367	1.5839	1.6328	1.6882	1.743	1.815	1.8502	1.9231	1.982	2.0599	2.1315	2.2168	2.2988	2.3804	2.469	2.5916	2.70%
Electricity	Transportati	49-IEO2021.	quad Btu	1.124	1.2249	1.3344	1.4536	1.5814	1.706	1.8325	1.9625	2.0936	2.2263	2.3616	2.495	2.6265	2.7542	2.8755	2.9969	3.1146	3.2314	3.3464	3.4604	7.10%
Total	Transportati	49-IEO2021.	quad Btu	58.5221	58.4001	58.322	58.3126	58.329	58.3417	58.3606	58.4088	58.5244	58.6335	58.8259	59.0471	59.3211	59.5955	59.9021	60.1702	60.4731	60.7814	61.1199	61.463	0.60%
United States		49-IEO2021.21.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	14.7045	14.6174	14.5535	14.5049	14.465	14.4239	14.386	14.3549	14.3366	14.3258	14.3192	14.3282	14.3488	14.3732	14.3959	14.4221	14.4512	14.4877	14.5318	14.5772	-0.10%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	6.22	6.1744	6.1373	6.1107	6.0899	6.0664	6.0437	6.0349	6.0274	6.0203	6.0146	6.0453	6.0682	6.0942	6.1064	6.1278	6.1448	6.1658	6.1877	6.2123	0.00%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.5665	0.5638	0.5601	0.5568	0.553	0.5501	0.5531	0.5458	0.5454	0.5214	0.5378	0.5099	0.5086	0.4915	0.502	0.4875	0.479	0.4763	0.4751	0.4715	0.30%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0072	0.0073	0.0074	0.0076	0.0077	0.0079	0.0081	0.0083	0.0085	0.0087	0.009	0.0093	0.0095	0.0098	0.0101	0.0105	0.0108	0.0112	0.0115	0.0119	2.50%
Jet fuel	Transportati	49-IEO2021.	quad Btu	3.6682	3.716	3.7661	3.8164	3.8659	3.9044	3.9383	3.9765	4.0163	4.0634	4.1095	4.1617	4.2158	4.2728	4.326	4.3767	4.4225	4.4648	4.5036	4.5427	2.40%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.1495	0.1494	0.1494	0.1494	0.1494	0.1494	0.1493	0.1493	0.1494	0.1494	0.1494	0.1496	0.1497	0.1498	0.15	0.1503	0.1505	0.1507	0.1509	0.151	0.20%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.7903	0.8068	0.8198	0.8332	0.8495	0.8632	0.8777	0.896	0.9109	0.9401	0.9562	0.9816	1.0053	1.0302	1.0467	1.074	1.0954	1.1157	1.1382	1.1627	1.30%
Electricity	Transportati	49-IEO2021.	quad Btu	0.1072	0.1168	0.1273	0.1388	0.1512	0.1645	0.1785	0.1935	0.2093	0.2262	0.2432	0.2608	0.2789	0.2977	0.3159	0.3347	0.3538	0.3734	0.3936	0.4139	8.50%
Total	Transportati	49-IEO2021.	quad Btu	26.2135	26.1519	26.1207	26.1178	26.1317	26.1298	26.1348	26.1593	26.2038	26.2553	26.339	26.4464	26.5848	26.7191	26.8531	26.9835	27.1079	27.2456	27.3924	27.5433	0.40%
Canada		49-IEO2021.31.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	1.3919	1.3734	1.354	1.335	1.3161	1.2972	1.2794	1.2591	1.2437	1.2212	1.2045	1.1883	1.174	1.1606	1.1494	1.1384	1.1294	1.1209	1.1137	1.107	-1.00%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	0.8523	0.8523	0.8536	0.8553	0.8587	0.861	0.8645	0.8673	0.8727	0.8769	0.8831	0.8886	0.8953	0.9016	0.9091	0.9151	0.9233	0.9311	0.9395	0.9441	0.70%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.0229	0.0227	0.0226	0.0224	0.0222	0.0219	0.0224	0.0221	0.0218	0.0214	0.021	0.0206	0.0201	0.0195	0.019	0.0183	0.0177	0.0184	0.0178	0.0171	-0.90%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0077	0.0075	0.0075	0.0074	0.0073	0.0072	0.0072	0.0071	0.007	0.007	0.0069	0.0069	0.0069	0.0068	0.0068	0.0067	0.0067	0.0066	0.0066	0.0066	-0.80%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.3294	0.3336	0.3378	0.3422	0.3467	0.3513	0.3551	0.359	0.3634	0.3682	0.3732	0.3785	0.3838	0.3892	0.3948	0.4006	0.4064	0.4124	0.4189	0.4256	3.80%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0056	0.0055	0.0055	0.0054	0.0054	0.0053	0.0055	0.0054	0.0053	0.0052	0.0051	0.005	0.0049	0.0048	0.0046	0.0045	0.0043	0.0045	0.0043	0.0042	-0.90%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.1835	0.1876	0.1933	0.2043	0.21	0.2159	0.2209	0.2274	0.2337	0.2407	0.2461	0.2526	0.2595	0.2659	0.2729	0.2804	0.2875	0.2918	0.2975	0.3075	2.40%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0189	0.0226	0.0268	0.0316	0.0366	0.0422	0.0473	0.0528	0.0582	0.0635	0.0687	0.0736	0.0784	0.0829	0.0872	0.0913	0.0951	0.0986	0.1017	0.1045	13.10%
Total	Transportati	49-IEO2021.	quad Btu	2.8122	2.8053	2.801	2.8036	2.803	2.8019	2.8024	2.8	2.8058	2.8042	2.8086	2.8141	2.8228	2.8314	2.8439	2.8553	2.8704	2.8843	2.9001	2.9165	0.40%
Mexico and Other		49-IEO2021.41.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	1.9643	1.983	2.0031	2.0275	2.0522	2.0796	2.109	2.1409	2.1775	2.2116	2.2491	2.287	2.3272	2.3656	2.4054	2.4395	2.474	2.5063	2.539	2.5701	1.60%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	0.972	0.9741	0.9756	0.98	0.9844	0.9904	0.9955	1.0007	1.007	1.0155	1.0253	1.0341	1.0442	1.0533	1.064	1.0718	1.0825	1.0924	1.1032	1.1097	1.00%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.0211	0.0212	0.0214	0.0215	0.0216	0.0217	0.0217	0.0218	0.0218	0.0218	0.0219	0.0219	0.0219	0.022	0.0221	0.022	0.022	0.022	0.022	0.022	0.50%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0026	0.0023	0.002	0.0017	0.0014	0.0011	0.0009	0.0007	0.0005	0.0003	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	-13.50%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.3704	0.3815	0.3924	0.4037	0.4141	0.4252	0.4365	0.448	0.4598	0.4715	0.4838	0.496	0.5086	0.5216	0.5353	0.5491	0.5637	0.5789	0.5948	0.6119	5.20%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0017	0.0017	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.50%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.02	0.0222	0.0245	0.027	0.0295	0.0322	0.0351	0.0381	0.0413	0.0448	0.0485	0.0525	0.0567	0.0611	0.0658	0.0707	0.076	0.0816	0.0874	0.0975	13.30%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0023	0.0027	0.0033	0.004	0.0048	0.0057	0.0066	0.0077	0.0089	0.0103	0.0117	0.0132	0.0141	0.015	0.0159	0.0169	0.0179	0.0188	0.0198	0.0207	14.30%
Total	Transportati	49-IEO2021.	quad Btu	3.3544	3.3887	3.424	3.4671	3.5098	3.5577	3.6071	3.6597	3.7187	3.7777	3.8424	3.9067	3.9745	4.0405	4.1103	4.172	4.238	4.3019	4.3681	4.4337	1.80%
OECD Europe		49-IEO2021.51.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	3.6538	3.6389	3.6156	3.5836	3.5443	3.5087	3.4698	3.43	3.3883	3.3401	3.2845	3.2251	3.16	3.0949	3.0298	2.9576	2.8839	2.8025	2.717	2.6254	-0.40%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	8.7918	8.5946	8.4046	8.2414	8.0874	7.9531	7.8213	7.695	7.5836	7.4849	7.4075	7.3338	7.281	7.2323	7.2063	7.1735	7.1664	7.1611	7.1653	7.1567	-0.80%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	1.5672	1.5704	1.5753	1.5784	1.5812	1.5768	1.5703	1.5631	1.5574	1.5457	1.5617	1.5553	1.546	1.5368	1.5287	1.512	1.4957	1.4792	1.4608	1.4407	0.00%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.2214	0.2242	0.2266	0.2285	0.2293	0.2308	0.2303	0.2282	0.2248	0.22	0.2148	0.2085	0.2016	0.1938	0.1853	0.1763	0.1668	0.1568	0.1465	0.1359	-0.10%
Jet fuel	Transportati	49-IEO2021.	quad Btu	3.3951	3.4577	3.5198	3.5787	3.6384	3.6956	3.7511	3.8098	3.8744	3.9426	4.0154	4.0933	4.172	4.2533	4.3364	4.4249	4.5133	4.602	4.7012	4.8034	4.10%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0998	0.1	0.1004	0.1006	0.1007	0.1005	0.1	0.0996	0.0992	0.0985	0.0995	0.0991	0.0985	0.0979	0.0974	0.0964	0.0953	0.0943	0.0931	0.0918	0.00%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.2434	0.2586	0.2751	0.2912	0.3086	0.3263	0.3451	0.3649	0.3867	0.4102	0.4104	0.4367	0.4628	0.4939	0.5255	0.5585	0.5931	0.6309	0.6696	0.7268	5.60%
Electricity	Transportati	49-IEO2021.	quad Btu	0.7535	0.8333	0.9208	1.0161	1.1186	1.218	1.3193	1.4227	1.5264	1.6313	1.7377	1.8423	1.9452	2.0439	2.1375	2.2303	2.3199	2.4084	2.4954	2.5817	8.10%
Total	Transportati	49-IEO2021.	quad Btu	18.726	18.6777	18.6381	18.6186	18.6085	18.6097	18.6073	18.6132	18.6408	18.6734	18.7315	18.7941	18.8671	18.947	19.0468	19.1295	19.2344	19.3351	19.4489	19.5624	0.80%

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Growth (2020-2050)
Japan		49-IEO2021.61.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	1.229	1.193	1.1609	1.1307	1.1017	1.0737	1.0472	1.0225	1.0001	0.9793	0.9606	0.9434	0.9273	0.9121	0.8981	0.8842	0.8716	0.8589	0.8465	0.8338	-1.60%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	0.8797	0.8667	0.8538	0.8431	0.8331	0.824	0.8149	0.8063	0.7995	0.7928	0.788	0.7827	0.7787	0.7742	0.7709	0.7662	0.7635	0.7606	0.758	0.7537	-0.50%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.2857	0.287	0.2882	0.2891	0.29	0.2896	0.2888	0.2878	0.287	0.285	0.2834	0.2817	0.2845	0.2826	0.2807	0.2771	0.2733	0.2691	0.2643	0.2586	0.00%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.001	0.0008	0.0007	0.0005	0.0004	0.0003	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	-11.10%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.4996	0.4993	0.4988	0.4977	0.4963	0.4943	0.4916	0.4881	0.485	0.4804	0.4756	0.4713	0.4673	0.4636	0.4604	0.4575	0.4549	0.4528	0.452	0.4527	1.70%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0362	0.0364	0.0366	0.0367	0.0368	0.0367	0.0366	0.0365	0.0364	0.0361	0.0359	0.0357	0.0361	0.0358	0.0356	0.0351	0.0346	0.0341	0.0335	0.0328	0.00%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.011	0.0121	0.0137	0.0154	0.0172	0.0192	0.0214	0.0239	0.0266	0.0296	0.033	0.0368	0.0352	0.0392	0.0435	0.0483	0.0537	0.0597	0.0663	0.0751	13.80%
Electricity	Transportati	49-IEO2021.	quad Btu	0.1287	0.132	0.1345	0.1372	0.1402	0.1415	0.1428	0.144	0.145	0.1458	0.1473	0.1486	0.1499	0.151	0.152	0.1535	0.1547	0.156	0.1572	0.1585	2.50%
Total	Transportati	49-IEO2021.	quad Btu	3.071	3.0274	2.987	2.9504	2.9157	2.8793	2.8435	2.8092	2.7798	2.7492	2.724	2.7004	2.6791	2.6585	2.6414	2.622	2.6064	2.5913	2.5779	2.5651	-0.40%
South Korea		49-IEO2021.71.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	0.4065	0.406	0.4052	0.4042	0.4031	0.4011	0.3989	0.3964	0.3935	0.39	0.3854	0.3802	0.3738	0.3668	0.3596	0.3519	0.3445	0.3368	0.3293	0.3215	-1.00%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	0.8318	0.8129	0.7945	0.7783	0.7632	0.7493	0.7355	0.722	0.7108	0.699	0.6902	0.6815	0.6745	0.6673	0.6615	0.654	0.6479	0.6418	0.6359	0.6291	-1.20%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.398	0.399	0.4005	0.4014	0.4023	0.4013	0.3998	0.398	0.3965	0.3935	0.3912	0.389	0.3935	0.391	0.3887	0.3841	0.3795	0.3748	0.3695	0.3635	-0.10%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0845	0.0802	0.0766	0.0734	0.0707	0.0683	0.0664	0.0647	0.0634	0.0619	0.0606	0.0594	0.0582	0.0571	0.0559	0.0548	0.0537	0.0525	0.0514	0.0502	-3.80%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.3192	0.3192	0.319	0.3186	0.3179	0.3168	0.3153	0.3133	0.3116	0.3089	0.306	0.3035	0.3012	0.299	0.2971	0.2955	0.294	0.2928	0.2924	0.293	1.80%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0	0	0	0	0	0	0	0	0	0	0	-4.80%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.0709	0.0733	0.0759	0.0786	0.0815	0.0845	0.0877	0.0911	0.095	0.0986	0.1028	0.1074	0.1046	0.1092	0.1142	0.1192	0.1247	0.1305	0.1368	0.1443	4.40%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0484	0.0494	0.0505	0.0516	0.0527	0.0536	0.0545	0.0554	0.0564	0.0571	0.058	0.0588	0.0598	0.0607	0.0616	0.0625	0.0633	0.0641	0.0649	0.0656	2.00%
Total	Transportati	49-IEO2021.	quad Btu	2.1593	2.1401	2.1222	2.1062	2.0916	2.0751	2.0581	2.041	2.0271	2.009	1.9943	1.9799	1.9656	1.9512	1.9387	1.922	1.9076	1.8935	1.8802	1.8673	-0.40%
Australia and New Zealand		49-IEO2021.81.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	0.6992	0.7044	0.7093	0.7147	0.7208	0.7267	0.7333	0.7404	0.7504	0.7542	0.7603	0.7658	0.7703	0.7739	0.7771	0.7794	0.7823	0.7845	0.7869	0.789	0.80%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	0.8678	0.8687	0.8675	0.8661	0.8638	0.8623	0.86	0.858	0.8564	0.8556	0.8577	0.8591	0.8631	0.8666	0.8704	0.8733	0.8793	0.8843	0.8898	0.8928	0.60%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.0399	0.04	0.0401	0.0402	0.0402	0.0401	0.04	0.0398	0.0396	0.0393	0.0391	0.0388	0.0385	0.0382	0.0379	0.0374	0.037	0.0376	0.0371	0.0366	0.10%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0107	0.0104	0.0102	0.01	0.0097	0.0095	0.0093	0.0092	0.0091	0.0089	0.0089	0.0089	0.0088	0.0089	0.0089	0.0089	0.009	0.009	0.0091	0.0091	-1.00%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.4675	0.4792	0.4907	0.502	0.5131	0.5233	0.5332	0.5425	0.5516	0.5606	0.5689	0.5768	0.585	0.5937	0.6023	0.6106	0.6195	0.6292	0.6395	0.6511	4.60%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0035	0.0035	0.0035	0.0034	0.0034	0.0033	0.0033	0.0032	0.0032	0.0031	0.0031	0.003	0.003	0.003	0.0029	0.0029	0.0029	0.0029	0.0029	0.0028	-0.40%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.032	0.0347	0.0364	0.0382	0.0403	0.0426	0.0448	0.0468	0.0488	0.0509	0.0532	0.0555	0.0579	0.0604	0.063	0.0657	0.0685	0.0703	0.0733	0.0776	4.90%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0651	0.068	0.0712	0.0743	0.0773	0.0805	0.0835	0.0865	0.0894	0.0921	0.095	0.0977	0.1004	0.103	0.1053	0.1077	0.1099	0.112	0.1139	0.1156	3.90%
Total	Transportati	49-IEO2021.	quad Btu	2.1857	2.2089	2.2289	2.249	2.2686	2.2883	2.3074	2.3263	2.3484	2.3648	2.3861	2.4056	2.4271	2.4478	2.4679	2.486	2.5083	2.5297	2.5524	2.5746	1.50%
Total Non-OECD		49-IEO2021.91.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	27.99	28.3796	28.7434	29.0997	29.4424	29.8063	30.1949	30.5881	30.9866	31.3801	31.7466	32.0852	32.3862	32.6582	32.9045	33.1093	33.3193	33.495	33.6702	33.821	1.60%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	25.6644	25.8228	25.9498	26.1075	26.258	26.4198	26.552	26.6641	26.8163	26.9362	27.1211	27.2797	27.4875	27.6741	27.9029	28.0678	28.287	28.4878	28.7004	28.8546	1.10%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	5.9563	5.9685	5.9844	5.9921	5.9977	5.9899	5.9734	5.9396	5.9093	5.8564	5.8875	5.849	5.7979	5.7366	5.693	5.6008	5.5108	5.4387	5.3668	5.2511	-0.10%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.1594	0.1528	0.1447	0.1354	0.1252	0.1152	0.1056	0.097	0.0896	0.0837	0.079	0.0752	0.0722	0.0695	0.0671	0.0649	0.0628	0.0607	0.0587	0.0569	-3.20%
Jet fuel	Transportati	49-IEO2021.	quad Btu	7.6699	7.9212	8.1666	8.4104	8.6515	8.8855	9.1174	9.3504	9.5853	9.8216	10.0532	10.2874	10.5184	10.7553	10.9968	11.2365	11.4787	11.7214	11.9702	12.2241	4.10%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.228	0.2284	0.2286	0.2283	0.2278	0.2265	0.2263	0.2243	0.2223	0.2197	0.2174	0.2147	0.2116	0.2083	0.2054	0.2012	0.1969	0.1927	0.1927	0.1879	-0.20%
Natural gas	Transportati	49-IEO2021.	quad Btu	4.8833	5.0715	5.2696	5.4808	5.7128	5.9423	6.1636	6.4149	6.6671	6.9391	7.1572	7.4398	7.7355	8.0357	8.3332	8.6422	8.9552	9.2555	9.5167	9.8666	4.10%
Electricity	Transportati	49-IEO2021.	quad Btu	1.7562	1.8494	1.9527	2.0647	2.1919	2.3118	2.4244	2.5433	2.6642	2.7894	2.9186	3.0476	3.1799	3.3155	3.4528	3.5938	3.7345	3.8769	4.0187	4.16	4.40%
Total	Transportati	49-IEO2021.	quad Btu	74.3075	75.3942	76.4398	77.5189	78.6074	79.6973	80.7577	81.8218	82.9407	84.0262	85.1806	86.2786	87.3893	88.4531	89.5556	90.5165	91.5452	92.5286	93.4945	94.4223	1.80%
Russia		49-IEO2021.101.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	1.3993	1.3992	1.3954	1.3952	1.3935	1.3888	1.3815	1.3731	1.3642	1.3544	1.3458	1.3365	1.3268	1.3169	1.3064	1.2951	1.2845	1.2731	1.2615	1.2491	-0.30%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	1.1896	1.1827	1.1732	1.1659	1.1598	1.1538	1.146	1.1385	1.1312	1.1238	1.1189	1.1118	1.1064	1.0997	1.0939	1.0853	1.0789	1.07	1.061	1.048	-0.20%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.0987	0.0986	0.0987	0.0986	0.0985	0.0979	0.099	0.0983	0.0977	0.0967	0.0959	0.0952	0.0942	0.0933	0.0949	0.0936	0.0923	0.091	0.0895	0.088	-0.20%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.4928	0.5015	0.5101	0.5183	0.5267	0.5352	0.5439	0.5523	0.5616	0.5708	0.5791	0.5882	0.5969	0.6069	0.617	0.6272	0.6375	0.6475	0.6581	0.6689	2.00%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	-0.20%
Natural gas	Transportati	49-IEO2021.	quad Btu	1.8086	1.8264	1.8438	1.8675	1.8955	1.9232	1.9502	1.9772	1.9997	2.0236	2.0494	2.0705	2.1008	2.1173	2.1532	2.175	2.2022	2.2283	2.2455	2.2695	1.50%
Electricity	Transportati	49-IEO2021.	quad Btu	0.2508	0.2491	0.2469	0.2446	0.2434	0.2408	0.2381	0.2367	0.2337	0.2323	0.2301	0.2278	0.2257	0.2234	0.2208	0.2185	0.2162	0.2137	0.2113	0.2088	-0.40%
Total	Transportati	49-IEO2021.	quad Btu	5.2401	5.2578	5.2683	5.2902	5.3175	5.3398	5.3588	5.3762	5.3883	5.4017	5.4193	5.4301	5.451	5.4576	5.4864	5.4947	5.5115	5.5237	5.5271	5.5325	0.60%
Other Non-OECD Europe and Eurasia		49-IEO2021.111.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	0.8679	0.8811	0.8957	0.9138	0.932	0.9512	0.9713	0.992	1.0137	1.0362	1.0581	1.0787	1.0981	1.1156	1.1306	1.1424	1.1532	1.1616	1.1689	1.1742	1.60%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	1.2791	1.2831	1.2869	1.2942	1.3014	1.3095	1.316	1.3213	1.3277	1.3352	1.3443	1.3507	1.3587	1.3654	1.3744	1.3802	1.3898	1.3987	1.4084	1.4133	0.70%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.286	0.2844	0.2863	0.2879	0.2895	0.2898	0.291	0.291	0.2914	0.2906	0.2906	0.2907	0.2902	0.2898	0.2922	0.2907	0.2894	0.288	0.2862	0.2841	0.30%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0343	0.0359	0.0371	0.0381	0.0388	0.0393	0.0395	0.0394	0.039	0.0384	0.0376	0.0364	0.035	0.0333	0.0313	0.0293	0.0274	0.0256	0.024	0.0225	4.40%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.184	0.1873	0.1905	0.1936	0.1968	0.1999	0.203	0.2062	0.2097	0.2132	0.2166	0.2202	0.2239	0.2278	0.2318	0.236	0.2402	0.2443	0.2487	0.2533	2.60%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0293	0.0291	0.0293	0.0295	0.0296	0.0297	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298	0.0297	0.0297	0.0299	0.0298	0.0296	0.0295	0.0293	0.0291	0.30%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.2844	0.2905	0.295	0.2981	0.3087	0.3315	0.3336	0.3383	0.3428	0.3538	0.3796	0.3849	0.3915	0.3986	0.4033	0.4121	0.4209	0.432	0.4416	0.4587	2.20%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0561	0.056	0.056	0.0559	0.0559	0.0557	0.0557	0.0557	0.0556	0.0558	0.0558	0.0558	0.0559	0.0559	0.0558	0.0559	0.0558	0.0558	0.0558	0.0558	0.00%
Total	Transportati	49-IEO2021.	quad Btu	3.0211	3.0474	3.0767	3.1111	3.1528	3.2065	3.24	3.2738	3.3097	3.3529	3.4124	3.4473	3.483	3.5161	3.5495	3.5764	3.6062	3.6355	3.6629	3.6909	1.20%

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Growth (2020-2050)
China		49-IEO2021.121.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	8.4724	8.4315	8.362	8.2647	8.1414	8.0228	7.9103	7.7859	7.6554	7.5214	7.38	7.2352	7.089	6.9435	6.7982	6.6491	6.5072	6.3643	6.2246	6.0851	-0.20%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	5.666	5.5828	5.4899	5.3997	5.3074	5.2139	5.113	5.0083	4.9091	4.8079	4.7155	4.6201	4.5329	4.4427	4.3603	4.2684	4.1893	4.1092	4.0335	3.9572	-1.20%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.7785	0.7801	0.7798	0.7783	0.7763	0.7713	0.7758	0.7697	0.7634	0.7546	0.7459	0.7366	0.7256	0.7137	0.7011	0.6848	0.6673	0.6482	0.6616	0.6418	-0.30%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0309	0.0287	0.0262	0.0235	0.0205	0.0176	0.0146	0.0118	0.0093	0.0071	0.0053	0.004	0.0031	0.0023	0.0022	0.0021	0.002	0.0019	0.0018	0.0017	-6.70%
Jet fuel	Transportati	49-IEO2021.	quad Btu	1.9508	2.0118	2.0711	2.1288	2.1852	2.2399	2.2929	2.3445	2.3938	2.443	2.4915	2.5412	2.5908	2.64	2.6886	2.7357	2.7816	2.8271	2.873	2.9183	2.90%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.1572	0.1575	0.1573	0.1567	0.1559	0.1544	0.1542	0.1523	0.1503	0.1478	0.1453	0.1427	0.1398	0.1368	0.1337	0.1301	0.1263	0.1222	0.1229	0.1187	-0.50%
Natural gas	Transportati	49-IEO2021.	quad Btu	1.5385	1.6269	1.7201	1.8156	1.9098	2.006	2.0909	2.195	2.2944	2.4048	2.5089	2.6248	2.7393	2.856	2.9637	3.0675	3.1693	3.2716	3.3246	3.4015	5.60%
Electricity	Transportati	49-IEO2021.	quad Btu	1.1499	1.2202	1.297	1.3781	1.4665	1.5496	1.6252	1.7007	1.775	1.8474	1.9196	1.989	2.0569	2.1223	2.1844	2.2444	2.2989	2.3509	2.3992	2.4444	4.40%
Total	Transportati	49-IEO2021.	quad Btu	19.7443	19.8396	19.9034	19.9453	19.963	19.9756	19.9769	19.9682	19.9506	19.9341	19.9119	19.8936	19.8773	19.8573	19.8322	19.782	19.742	19.6955	19.6411	19.5687	0.80%
India		49-IEO2021.131.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	2.386	2.5291	2.6667	2.8007	2.9288	3.065	3.2059	3.3446	3.4794	3.6075	3.7248	3.8328	3.9247	4.0021	4.0626	4.1032	4.129	4.1346	4.1268	4.1004	4.40%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	4.7606	4.9391	5.1076	5.2743	5.4314	5.5915	5.7461	5.8899	6.0394	6.1791	6.3266	6.4645	6.6112	6.7467	6.8899	7.0099	7.1386	7.2552	7.3762	7.4699	3.70%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.1235	0.125	0.1264	0.1276	0.1287	0.1293	0.1299	0.1303	0.1308	0.1309	0.1311	0.1312	0.1311	0.1308	0.1306	0.1297	0.1287	0.1303	0.1291	0.1278	0.80%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0265	0.0254	0.0245	0.0233	0.0221	0.0212	0.0204	0.0198	0.0192	0.0188	0.0186	0.0184	0.0184	0.0184	0.0184	0.0183	0.0181	0.0177	0.0174	0.0169	-2.70%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.5393	0.5681	0.5963	0.624	0.6512	0.677	0.7032	0.7299	0.7582	0.7867	0.8139	0.8415	0.8688	0.8968	0.9257	0.9536	0.9811	1.009	1.0367	1.0635	6.20%
Other liquids	Transportati	49-IEO2021.	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.582	0.6132	0.6483	0.6812	0.7192	0.7523	0.7912	0.8323	0.8765	0.9192	0.9642	1.0118	1.059	1.1068	1.1504	1.201	1.2503	1.2986	1.3395	1.3933	5.80%
Electricity	Transportati	49-IEO2021.	quad Btu	0.2116	0.2338	0.2596	0.2897	0.326	0.3613	0.3965	0.4366	0.481	0.5291	0.582	0.6371	0.6964	0.7611	0.8309	0.9059	0.9855	1.0685	1.1547	1.2432	8.80%
Total	Transportati	49-IEO2021.	quad Btu	8.6296	9.0338	9.4294	9.8207	10.2076	10.5977	10.9933	11.3834	11.7846	12.1714	12.5612	12.9374	13.3096	13.6628	14.0085	14.3216	14.6312	14.914	15.1804	15.4149	4.30%
Other Non-OECD Asia		49-IEO2021.141.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	5.1444	5.2996	5.4575	5.6231	5.7971	5.9696	6.1485	6.3355	6.529	6.725	6.9147	7.1022	7.2805	7.4537	7.6246	7.7862	7.9532	8.1174	8.2859	8.454	2.90%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	4.0519	4.0583	4.0639	4.0761	4.0896	4.1038	4.1153	4.1258	4.1454	4.1609	4.1871	4.2127	4.2496	4.2874	4.3351	4.3766	4.4197	4.4679	4.5142	4.5623	1.00%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	2.6964	2.7075	2.7111	2.7104	2.7081	2.6918	2.6707	2.6465	2.623	2.5872	2.6305	2.6035	2.5693	2.5324	2.494	2.4386	2.3799	2.3167	2.2459	2.1669	-0.40%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0194	0.0179	0.0166	0.0155	0.0146	0.0138	0.0133	0.0129	0.0125	0.0121	0.0117	0.0114	0.0111	0.0108	0.0107	0.0106	0.0107	0.0108	0.011	0.0112	-2.50%
Jet fuel	Transportati	49-IEO2021.	quad Btu	2.2313	2.3082	2.3824	2.4554	2.5272	2.5943	2.6585	2.7235	2.7885	2.8521	2.9131	2.9716	3.0276	3.0839	3.1404	3.1934	3.2454	3.2939	3.3438	3.3953	4.60%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108	0.0107	0.0106	0.0105	0.0103	0.0105	0.0104	0.0103	0.0101	0.01	0.0097	0.0095	0.0093	0.009	0.0087	-0.40%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.2372	0.2532	0.2815	0.313	0.3481	0.3853	0.4262	0.471	0.5205	0.5727	0.5538	0.609	0.668	0.732	0.8014	0.8741	0.9522	1.0355	1.1247	1.2287	8.70%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0115	0.0127	0.0142	0.0159	0.0178	0.0201	0.0225	0.0251	0.028	0.0312	0.0347	0.0385	0.0427	0.047	0.0516	0.0563	0.0611	0.0661	0.0711	0.0763	8.40%
Total	Transportati	49-IEO2021.	quad Btu	14.4028	14.6683	14.9381	15.2203	15.5134	15.7894	16.0655	16.3508	16.6573	16.9515	17.2562	17.5594	17.859	18.1575	18.4677	18.7456	19.0318	19.3177	19.6056	19.9033	2.20%
Middle East		49-IEO2021.151.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	2.9044	2.8999	2.9035	2.9142	2.9302	2.9534	2.9822	3.0161	3.0525	3.0916	3.1243	3.1499	3.1703	3.185	3.195	3.2057	3.2217	3.2386	3.2617	3.2859	0.10%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	2.3306	2.332	2.3312	2.3353	2.3398	2.3468	2.3493	2.3516	2.3578	2.3584	2.3652	2.3685	2.3742	2.3779	2.3849	2.3844	2.3895	2.391	2.3935	2.3926	0.60%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	1.2564	1.2513	1.2549	1.2571	1.2594	1.2704	1.2662	1.2616	1.2586	1.2511	1.2467	1.243	1.2375	1.2324	1.2286	1.2185	1.2092	1.2192	1.2098	1.1995	0.00%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.0064	0.0063	0.0062	0.006	0.0057	0.0055	0.0052	0.005	0.0048	0.0047	0.0046	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0044	0.0044	0.0044	-0.20%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.9902	1.0194	1.048	1.0771	1.1063	1.1348	1.1645	1.1945	1.2248	1.2561	1.2875	1.3192	1.3489	1.3795	1.4115	1.4453	1.4808	1.5175	1.5557	1.5955	4.30%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.003	0.0029	0.0029	0.003	0.003	0.003	0.003	0.003	0.003	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0028	0.0029	0.0028	0.0028	0.00%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.2272	0.2466	0.2597	0.2733	0.2877	0.2873	0.3017	0.3173	0.3345	0.3516	0.3701	0.3897	0.4098	0.4312	0.4534	0.4761	0.4999	0.506	0.5306	0.5591	6.40%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0044	0.0043	0.0042	0.004	0.0038	0.0037	0.0036	0.0034	0.0033	0.0031	0.003	0.0028	0.0027	0.0026	0.0024	0.0023	0.0022	0.0021	0.002	0.0019	-2.90%
Total	Transportati	49-IEO2021.	quad Btu	7.7227	7.7627	7.8105	7.8699	7.9359	8.0049	8.0757	8.1525	8.2392	8.3195	8.4043	8.4806	8.5507	8.6161	8.6832	8.7398	8.8106	8.8817	8.9607	9.0417	0.90%
Africa		49-IEO2021.161.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	3.0657	3.1492	3.2324	3.3188	3.409	3.5032	3.6011	3.7032	3.8054	3.9142	4.021	4.1267	4.2295	4.3315	4.4339	4.5361	4.6412	4.7407	4.842	4.941	3.20%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	3.1058	3.1517	3.197	3.2492	3.3028	3.3601	3.4147	3.4675	3.5276	3.5809	3.6519	3.7217	3.8022	3.8827	3.9698	4.0524	4.1481	4.244	4.3418	4.4325	2.00%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.1542	0.1553	0.1564	0.1574	0.1584	0.1587	0.1588	0.1589	0.1591	0.1598	0.1599	0.1601	0.16	0.1599	0.1599	0.1592	0.1584	0.1596	0.1588	0.1578	0.40%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0.042	0.0386	0.0342	0.0291	0.0234	0.0178	0.0126	0.0082	0.0048	0.0025	0.0011	0.0004	0.0002	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	-17.30%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.5786	0.598	0.617	0.6371	0.6578	0.6791	0.701	0.7236	0.746	0.7693	0.7925	0.817	0.8422	0.869	0.8972	0.9266	0.9575	0.9902	1.0228	1.057	5.50%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0188	0.0189	0.019	0.0192	0.0193	0.0193	0.0193	0.0193	0.0194	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0194	0.0193	0.0194	0.0193	0.0192	0.40%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.0741	0.0784	0.0833	0.0884	0.0942	0.1002	0.1068	0.1134	0.1206	0.1271	0.1354	0.1437	0.1519	0.1605	0.1685	0.179	0.1893	0.1986	0.2109	0.2304	6.00%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0363	0.0368	0.0375	0.0382	0.039	0.0399	0.0408	0.0418	0.0429	0.0441	0.0453	0.0466	0.0481	0.0496	0.0512	0.0529	0.0551	0.0579	0.0609	0.064	2.40%
Total	Transportati	49-IEO2021.	quad Btu	7.0754	7.2269	7.377	7.5373	7.7037	7.8782	8.0552	8.2359	8.4257	8.6174	8.8266	9.0357	9.2537	9.4728	9.7001	9.9255	10.169	10.4105	10.6567	10.9022	2.70%
Brazil		49-IEO2021.171.																						
Motor gasoline and E85	Transportati	49-IEO2021.	quad Btu	2.1464	2.1592	2.1719	2.1858	2.201	2.217	2.2326	2.2483	2.2647	2.2802	2.2965	2.3107	2.323	2.3331	2.3425	2.3484	2.3541	2.359	2.3647	2.3698	0.80%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.	quad Btu	1.8809	1.8846	1.8847	1.8875	1.8899	1.8928	1.8927	1.8909	1.8926	1.8915	1.8951	1.8965	1.8997	1.901	1.9049	1.9035	1.9059	1.9061	1.9067	1.8998	0.70%
Residual fuel oil	Transportati	49-IEO2021.	quad Btu	0.1522	0.1532	0.1543	0.1554	0.1564	0.1569	0.1572	0.1575	0.158	0.1581	0.1584	0.1588	0.159	0.1574	0.1578	0.1576	0.1575	0.1575	0.1574	0.1572	0.50%
Liquefied petroleum gas	Transportati	49-IEO2021.	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%
Jet fuel	Transportati	49-IEO2021.	quad Btu	0.3219	0.3339	0.346	0.3584	0.3709	0.3833	0.3959	0.4086	0.4222	0.4364	0.451	0.4664	0.4824	0.499	0.5164	0.5342	0.5531	0.5727	0.5933	0.6145	5.20%
Other liquids	Transportati	49-IEO2021.	quad Btu	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0022	0.0022	0.0022	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.50%
Natural gas	Transportati	49-IEO2021.	quad Btu	0.0754	0.0779	0.0765	0.0793	0.0821	0.0859	0.0888	0.0924	0.0962	0.1001	0.1046	0.1091	0.1139	0.1208	0.126	0.1321	0.1382	0.1446	0.1509	0.163	4.10%
Electricity	Transportati	49-IEO2021.	quad Btu	0.0348	0.0356	0.0367	0.0377	0.0389	0.0402	0.0415	0.0429	0.0444	0.046	0.0477	0.0495	0.0513	0.0532	0.0552	0.0573	0.0594	0.0615	0.0635	0.0655	2.90%
Total	Transportati	49-IEO2021.	quad Btu	4.6137	4.6466	4.6721	4.7061	4.7414	4.7781	4.8109	4.8428	4.8803	4.9145	4.9555	4.9931	5.0314	5.0667	5.105	5.1352	5.1704	5.2034	5.2387	5.272	1.10%

Transportation sector energy consumption by region and fuel
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-IEO2021&region=0-0&cases=Reference&start=2010&end=2050&f=A&linechart=Reference-d210719.3-49-IEO2021&ctype=linechart&sourcekey=0
Tue Mar 29 2022 03:51:18 GMT-0700 (Pacific Daylight Time)
Source: U.S. Energy Information Administration

	full name	api key	units	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Growth (2020-2050)
Other Non-OECD Americas		49-IEO2021.181.																						
Motor gasoline and E85	Transportati	49-IEO2021.:	quad Btu	1.6034	1.6308	1.6583	1.6835	1.7092	1.7352	1.7616	1.7895	1.8222	1.8496	1.8813	1.9125	1.9443	1.9768	2.0107	2.043	2.0753	2.1055	2.1343	2.1614	2.50%
Distillate fuel oil and biodiesel	Transportati	49-IEO2021.:	quad Btu	1.3999	1.4084	1.4154	1.4254	1.4359	1.4477	1.4589	1.4703	1.4855	1.4986	1.5166	1.533	1.5524	1.5705	1.5896	1.6071	1.6273	1.6456	1.6649	1.6789	1.60%
Residual fuel oil	Transportati	49-IEO2021.:	quad Btu	0.4103	0.4131	0.4164	0.4194	0.4225	0.4238	0.4248	0.4257	0.4272	0.4273	0.4285	0.43	0.4309	0.4268	0.4339	0.4282	0.4281	0.4284	0.4283	0.428	0.50%
Liquefied petroleum gas	Transportati	49-IEO2021.:	quad Btu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%
Jet fuel	Transportati	49-IEO2021.:	quad Btu	0.3809	0.393	0.4052	0.4177	0.4295	0.442	0.4545	0.4673	0.4806	0.494	0.5081	0.5222	0.5369	0.5522	0.5682	0.5844	0.6016	0.6194	0.6381	0.6579	5.20%
Other liquids	Transportati	49-IEO2021.:	quad Btu	0.0068	0.0068	0.0069	0.0069	0.007	0.007	0.007	0.007	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0072	0.0071	0.0071	0.0071	0.0071	0.0071	0.50%
Natural gas	Transportati	49-IEO2021.:	quad Btu	0.0557	0.0583	0.0614	0.0644	0.0674	0.0707	0.0742	0.0779	0.082	0.0861	0.0912	0.0961	0.1014	0.1126	0.1133	0.1256	0.1327	0.1404	0.1483	0.1624	5.20%
Electricity	Transportati	49-IEO2021.:	quad Btu	0.0007	0.0007	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	-3.50%
Total	Transportati	49-IEO2021.:	quad Btu	3.8577	3.9112	3.9643	4.018	4.0721	4.127	4.1815	4.2383	4.305	4.3631	4.4331	4.5014	4.5735	4.6464	4.7231	4.7956	4.8724	4.9467	5.0214	5.0961	2.20%

Source: IEA Oil Information https://www.iea.org/data-and-statistics/data-product/oil-information
Documentation: https://iea.blob.core.windows.net/assets/41f0451c-3db9-45ea-b3d9-6f28ac7536ff/Oil_documentation.pdf

	LPG/Ethane	Naphtha	Motor gasoline	Jet kerosene	Other kerosene	Gas/Diesel	Fuel oil	Other oil products	Crude oil/NGL	Units
1990	6064650	4810322	30594725	6752501	3212852	32219935	13374621	8409209	443658	TJ
1995	7654684	5953111	32369489	7497161	3465923	34812231	12708740	8589203	448411	TJ
2000	9080924	7402507	34775268	8957781	3697770	39051198	12865832	9855856	551827	TJ
2005	9739649	8656019	37276438	9779846	3138157	44995397	13275410	12353777	505084	TJ
2010	10954585	9443641	38586636	10066800	2304432	47992988	12631981	12910120	866466	TJ
2015	12553893	9838826	41860220	11693516	1696424	52374276	10634679	13982208	520056	TJ
2019	14515436	10151000	44172811	13822381	1397019	53206480	10065526	15578945	562460	TJ

Phillips 66

San Francisco Refinery

Rodeo, California

BAAQMD Plant 16

Flare

Minimization

Plan (FMP)

Non-Confidential version

Bay Area Air Quality Management District (BAAQMD), Regulation 12, Rule 12

Environmental Protection Agency (EPA), 40 CFR 63 Subpart CC

October 2020, Revision 19

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1.0 Flare Minimization Plan

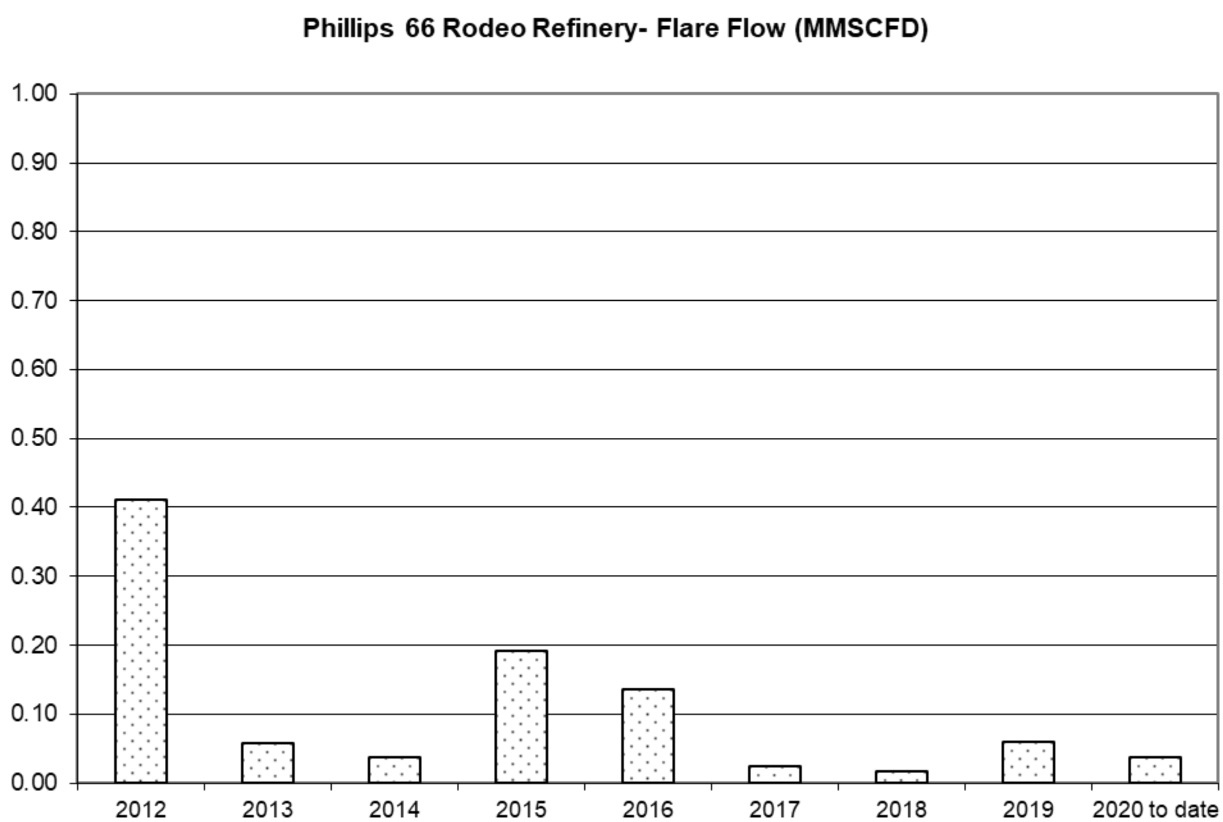
Regulation 12, Rule 12, was adopted by the BAAQMD in July, 2005, with the objective of reducing emissions from flares at petroleum refineries. This flare minimization plan for the Phillips 66, San Francisco Refinery (SFR) located in Rodeo, CA is consistent with progress toward that goal. It defines a series of measures that will lead to minimization of flaring without compromising refinery operations and practices with regard to safety. The key tools utilized are careful planning to minimize flaring, measuring and monitoring of flare events when they occur, coupled with evaluation of the cause of flaring events that do occur. Using this approach, an understanding of the events leading to the flaring event can then be incorporated into future planning and flare minimization efforts. The plan also examines the costs and benefits of potential equipment modifications to further increase flare gas recovery.

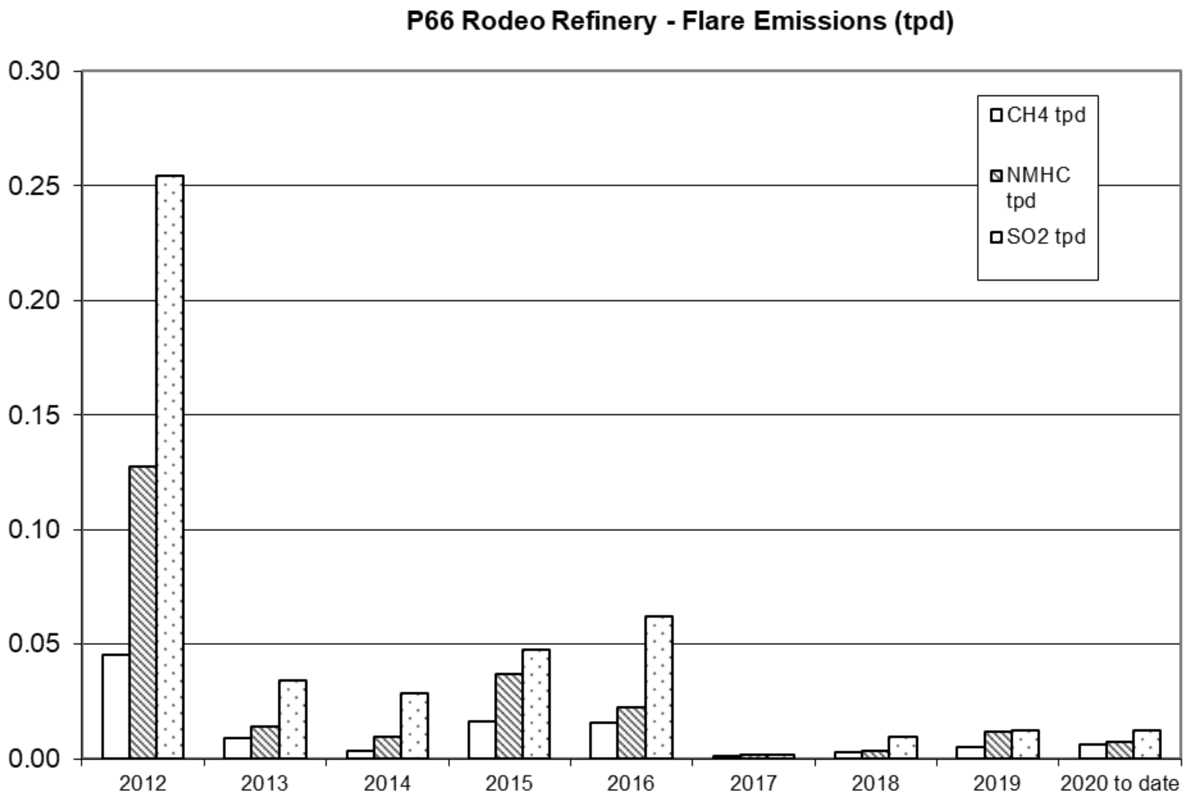
1.1 Safety Statement

This Flare Minimization plan outlines the approach that Phillips 66, San Francisco Refinery has developed to manage and minimize flaring events, without compromising the critical safety function of the flare system. Flares are first and foremost devices to ensure the safety of refinery operations and personnel. Nothing in the BAAQMD 12-12 rule or in this Flare Minimization Plan (FMP) should be construed to compromise refinery operations and practices with regards to safety.

1.2 Executive Summary

Shown below are graphical representations of historical flare flow and emissions from the period of 2011 to June 30, 2020:





The Rodeo Refinery installed and has utilized a Flare Gas Recovery Compressor since the mid-70's. Historic practices emphasized flare minimization. Some of the recent flaring reductions have occurred due to improved monitoring and tracking of flare volumes as well as attributing causes to all flaring as required by BAAQMD 12-11 and 12-12 and internal policies for incident investigation. Other efforts to minimize flare emissions have occurred through communication and improved awareness.

Higher flare volumes in 2012 and 2016 were due to significant turnaround activities taking place. Key pressure vessels in the flare gas recovery system were removed from service for required 10-year vessel metallurgical inspections in 2016. Although similar turnaround activities took place in 2012 and 2016, a significant reduction in flare volume, duration and SO_2 emissions were achieved in 2016 relative to 2012. In 2012 there was a large turnaround which contributed to higher than usual year to date flows. Following the turnaround, a relief valve leaking to the flare was discovered. An engineered solution was developed in order to isolate and provide an alternative relief path. In 2012 there were also a number of periods of fuel gas imbalance in which scrubbed fuel gas was sent to the flare.

In the second half of 2010 the facility experienced a number of flaring events due to the unplanned shutdowns of the 3rd party Hydrogen supplier. Phillips 66 worked closely with the 3rd party Hydrogen supplier to improve reliability at their facility. Work began in 2010 and continued up until mid-2011 when the supplier made significant equipment reliability upgrades during a planned shutdown.

In August 2009 three new, redundant liquid ring Flare Gas Recovery Compressors were installed and put in service. The purpose of the new compressors is to provide additional capacity on a consistent basis and to provide for backup compressor capacity. The new compressors are of a different design than the existing compressor and are designed to handle a wider range of composition and of flare gas. They are also less susceptible to liquid carryover impacts.

Based on a review of small flaring events, the addition of the new Flare Gas Recovery Compressors has reduced the number and volume of brief peak exceedances that previously occurred. This trend was observed since 2009. More importantly, the new compressors were operated on a regular basis while the older compressor was shutdown for major planned maintenance activities. In the past this type of maintenance activity would have resulted in consecutive days of flaring. In these cases the new compressors picked up the flare gas recovery load for a number of days and were effective in reducing flaring volumes.

Another improvement which has occurred is due to improved planning prior to the occurrence of flare activity. Flaring typically occurs during turnarounds when either the gas quality or quantity is not recoverable by the Fuel Gas Recovery Compressor or System. Turnaround planning is conducted to review the periods when flaring may occur. Prior to the turnaround activity, a team discusses these periods in order to determine methods to minimize flaring. In addition, in 2012 a process of further addressing impacted plant systems (e.g. fuel gas, steam, flaring, etc.) was formalized. This high level overview helps to early identify systems which can be optimized prior to a turnaround and in some cases can further reduces flaring.

In early 2011 the manner in which Unit 110 Hydrogen Plant shutdown and startups was changed. This resulted in a significant reduction in the period of flaring which occurs during each of these activities. During 2012 there were a number of periods of flaring associated with Unit 110. Work continued in 2012 and 2013 to further improve procedures to minimize flaring associated with Unit 110 startups and shutdowns. Additionally, although not apparent from the flare trends, there are a number of unit shutdowns that occur each year in which little or no flaring occurs. This is due to past implemented and current practices to reduce flaring.

One of the focus items for flare reduction is fuel gas imbalance. In December 2011 a permit application was submitted to revise permit limits at the Steam Power Plant (SPP). This would allow more refinery fuel gas to be sent to SPP during periods of fuel gas imbalance which typically occur while large turnarounds are taking place. Combustion of purchased natural gas, would be reduced while reducing or eliminating flaring. BAAQMD Permitting is continuing to review this permit application.

The Rodeo Refinery went 11 months, from July 2013 until June 2014 without a Reportable Flaring Event. Recently the facility went from July 2017 through August 2018 without a Reportable Flaring Event. This milestone is due to a combination of improved reliability, on-going focus on flare minimization operating enhancements to prevent flaring and light turnaround activity.

1.3 Certification

I certify that, based on the information available to me, the flare minimization plan is accurate, true, and complete.

Kevin Schmitt – Operations Manager

1.4 Revisions to the Flare Management Plan

Pursuant to BAAQMD 12-12-404 the Flare Minimization Plan is required to be updated, as appropriate, and submitted annually for review and approval by BAAQMD. The facility must revise and submit the FMP prior to the installation or modification of the equipment referenced in 401.1.1.

Pursuant to 40 CFR 63.670(o)(2)(ii), the facility would also be required to update this plan periodically to account for changes in the operation of a flare, such as;

- installation of a flare gas recovery system (update only), or
- change in the design of the smokeless capacity (requires re-submittal)

2.0 Flare System Information

2.1 Background Information for Flare Systems

Refineries process crude oil by separating it into a range of components, or fractions, and then rearranging those components to better match the yield of each fraction with market demand. Petroleum fractions include heavy oils and residual materials used to make asphalt or petroleum coke, mid range materials such as diesel (heating oil), jet fuel and gasoline, and lighter products such as butane, propane, and fuel gases.

The San Francisco Refinery is organized into groups of process units, with the general goal of maximizing the production of transportation fuels. Each unit takes in a set of feed streams and produces a set of product streams with the composition changed (or upgraded) as one step toward production of an optimal mix of refined products. Many of these processes operate at elevated temperatures and pressures, and a critical element of safe design is having the capability of releasing excess pressure via relieving devices to the flare header to manage excess materials in a controlled manner. These separation and rearrangement processes also produce and/or consume materials that are gases at atmospheric pressure. As a final step in processing, many units provide treatment to conform to environmental specifications such as reduced sulfur levels.

The refinery is designed and operated so that there will be a balance between the rates of gas production and consumption. Under normal operating conditions, essentially all gases that are produced are routed to the refinery fuel gas system, allowing them to be used for combustion in refinery heaters and boilers. Typical refinery fuel gas systems are configured so that the fuel gas header pressure is maintained by making up natural gas to meet the net fuel requirement. This provides a simple way to keep the system in balance so long as gas needs exceed the volume of gaseous products produced. Additional operational flexibility is typically maintained by having the ability to add butane and having the capability to adjust the rate of fuel gas consumption to a limited extent at the various refinery users (e.g. heaters, boilers, cogeneration units).

A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. These are referred to as “flare headers”, as the ultimate destination for any net excess of gas is a refinery flare. One of the primary functions of the flare header is safety. It provides the process unit with a controlled outlet for any excess vapor flow, making it an essential safety feature of every refinery. The flare header also has connections for equipment depressurization and purging related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices to handle upsets, malfunctions, and emergency releases.

Knockout drums are in place for separation of entrained liquid. This minimizes the possibility of liquid being carried forward to the flare or flare gas compressor. The vapor stream from the unit knockout drum is then routed to the refinery flare gas recovery system.

The refinery flare system consists of a series of branch lines from various unit collection systems which join a main flare header. The main flare header is in turn connected to both a flare gas recovery system and to the flares. Normally all vapor flow to the flare header is recovered by the flare gas recovery compressor, which increases the pressure of the flare gas allowing it to be routed to a gas treater for removal of contaminants such as sulfur and then to the refinery fuel gas system. Gases that cannot be recovered or used by the flare gas recovery compressor, the treater(s), and/or the fuel gas system end users flows to a refinery flare so it can be safely disposed of by combustion.

A flare seal drum is located at the base of each flare to serve several functions. A level of water is maintained in the seal drum to create a barrier which the gas must cross in order to get to the flare stack. The depth of liquid maintained in the seal determines the pressure that the gas must reach in the flare header before it can enter the flare. This creates a positive barrier between the header and the flare, ensuring that so long as the flare gas recovery system can keep pace with net gas production, no gas from the flare header will flow to the flare. It also guarantees a positive pressure at all points along the flare header, eliminating the possibility of air leakage into the system. Finally it provides a positive seal to isolate the flare, which is an ignition source, from the flare gas header and the process units. The flare systems combine two flares with different water seal depths, effectively "staging" operation of the flares.

Gases exit the flare via a flare tip which is designed to promote proper combustion over a range of gas flowrates. Steam is used to improve mixing between air and hydrocarbon vapors at the flare tip, so as to improve the efficiency of combustion and reduce smoking. A continuous flow of gas to each flare is required for two reasons. Natural gas pilot flames are kept burning at all times at the flare tip to ignite any gas flowing to the flare. Additionally, a small purge gas flow is required to prevent air from flowing back into the flare stack.

The sources of normal or base level flow to the refinery flare gas collection system are varied, but in general result from many small sources such as leaking relief valves, instrument purges, and pressure control for refinery equipment items (e.g. overhead systems for distillation columns). Added to this base load are small spikes in flow from routine maintenance operations, such as clearing hydrocarbon from a pump or filter by displacing volatiles to the flare header with nitrogen or steam. Additional flare load results from routine process functions, such as drum depressurization at the delayed coking unit.

Flaring often occurs during unit startups and shutdowns or when pieces of equipment associated with units are taken out of service. Equipment maintenance results in the need for removal of hydrocarbon from process equipment and associated piping before opening, for both safety and environmental reasons including compliance with BAAQMD Regulation 8 Rule 10. Typical decommissioning procedures include multiple steps of depressurization, and purging with nitrogen or steam to the flare header. During these steps, the quality of the fuel gas is degraded and at times cannot be recovered. During startups, low quality gases may also be produced which are not desirable to be recovered. Additionally, when multiple units are shutdown, flaring can occur when gases are being produced at one unit and an interrelated unit which normally utilizes the gases, such as hydrogen, have not yet been started up.

Although maintenance-related flows can be large, the design and sizing of refinery flare systems is without exception driven by the need for safe disposal of much larger quantities of gases during upsets and emergencies. A major emergency event, such as a total power failure, will require the safe disposal of a very large quantity of gas and hydrocarbon materials during a very short period of time in order to prevent a catastrophic increase in system pressure. The flow that the flare system could be called upon to handle during an event of this type is several orders of magnitude greater than the normal or baseline flowrate.

2.2 Technical Data – Description of Flaring Systems (401.1)

This section contains the information required under 401.1 in regards to required Technical Data.

2.2.1 Phillips 66, San Francisco Refinery Flare & Fuel Gas Recovery System Overview

2.2.1.1 General Flare Gas System Overview

The Phillips 66 Rodeo Refinery has a flare gas recovery system in which liquids and gases are recovered the majority of the time, cleaned, and utilized as fuel gas in facility heaters and the co-generation plant. When gases cannot be recovered due to quality or quantity issues gases would be routed to the flare. There are two flares on site which function in a semi-cascading manner. The C-1 Main Flare (S-296) is the primary flare that is utilized. The MP-30 Flare (S-398) is used during significant events (i.e. major utilities failure) and during times in which the Main Flare is shut down for maintenance. The Refinery flare system consists of the following key components:

- Flare gas compressor recovery system;
- Liquid recovery system;
- Video monitoring system;
- Flare gas flow measurement system;
- Automated flare gas sampling system, and
- Smokeless flare installation.

See Attachment A for simplified diagram of the flare gas recovery system. Attachment B contains a detailed description of the refinery flare gas system. Attachments K and L contain information on the flares and compressors, respectively.

2.2.2 Detailed process flow diagram, PFD (401.1.1)

See Attachment C for PFD of SFR Flare System components. The PFD contains the information required under 401.1.1. The PFD contains the pipelines, process unit blowdown origins, flare gas recovery system equipment, water seals, surge drums, knock-out pots, and other equipment associated with the flare system. The drawing contains the dimensions and capacities of the flare gas recovery system, compressor, water seals, surge drums, and knockout pots.

2.2.3 Description of Monitoring and Control Equipment (401.1.2)

Locations of flowmeters, temperature and pressure indicators are shown on the PFDs referenced in the section above. Locations of sample points and monitoring equipment are also shown on the PFDs. Listed below are the monitors and controls associated with the flare gas recovery system as required by 401.1.2.

2.2.3.1 C-1 Main Flare (S-296)

Flare System Flowmeters

Main Flare (S-296) – Flare System Flowmeters				
Tag Number	***Description***	***Location***	***Type (e.g. sonic)***	***Range (X – Y scfd)***
Flare Gas Flow:				
RFLRE:19FI0520	Main Flare 42" Line	42" Line - Upstream of Flare Stack Water Seal (C-1)	Ultrasonic Flowmeter	0 - 60,000
RFLRE:19FI0520l.	42" Line - low range			0 - 2,000
RFLRE:19FI0520h.	42" Line - high range			0 - 60,000
RFLRE:19FI0513A.	Main Flare 42" Line	42" Line - Upstream of Flare Stack Water Seal (C-1)	Anemometer [1]	0 - 110,000
RFLRE:19FI0586	Main Flare 10" Line	10" Line - From U200 & U267	Ultrasonic Flowmeter	0 - 20,000
RFLRE:19FI0586l.	10" Line - low range			0 - 2,000
RFLRE:19FI0586h.	10" Line - high range			0 - 20,000

Main Flare (S-296) – Flare System Flowmeters				
Tag Number	***Description***	***Location***	***Type (e.g. sonic)***	***Range (X – Y scfd)***
RFLRE:19FI0513.	Main Flare 10" Line	10" Line - From U200 & U267	Anemometer [1]	0 - 6000
Purge Gas Flow:				
RFLRE:19FIC0510.	Natural Gas Purge	Purge into Flare Stack (C-1) RSR	Orifice Plate	Low: 0 – 1,689 MSCFD High: 0 – 3,120 MSCFD
RFLRE:19FI0521.	Natural Gas Purge	Purge into Flare Stack (C-1)	Orifice Plate	0 - 25 MSCFD
Steam Gas Flow				
RFLRE:FI2673	Steam Meter	Steam to Flare RSR	Ultrasonic	0 – 100 Mlb/hr

[1] Does not meet 12-11 accuracy requirements for all ranges. Utilized as a backup meter, when necessary.

Continuous Recording Instruments

Main Flare (S-296) – Continuous Recording Instruments			
Tag Number	***Description***	***Location***	***Instrument Type***
Pressure			
RFLRE:19PIC0530.	200:19F-1 PRESSURE	Refinery Relief Blowdown Drum (F-1) Pressure	Pressure Indicator
RFLRE:19PI0520.	42" Line - Upstream of Flare Stack Water Seal (C-1) (integrated with ultrasonic flowmeter)	42" Line - Upstream of Flare Stack Water Seal (C-1)	Pressure Indicator
RFLRE:19PI0586.	Main Flare 10" Line (integrated with ultrasonic flowmeter)	10" Line - From U200 & U267	Pressure Indicator
Level			
RFLRE:19LIC0512.	200:19F-3 Water Seal Level	19F-3 Water Seal	Water Seal Level Indicator
RFLRE:19LI0508.	200:19C-1 Flare Stack Water Seal Level	19C-1 Flare Stack	Water Seal Level Indicator
Temperature			
RFLRE:19TI0520.	200:Flare Blowdown Line Temperature	42" Line - Upstream of Flare Stack Water Seal (C-1)	Temperature
RFLRE:19TI0586.	200:10” Line Flare Blowdown Line Temperature	10" Line - From U200 & U267	Temperature

Main Flare (S-296) – Continuous Recording Instruments			
Tag Number	***Description***	***Location***	***Instrument Type***
RFLRE:19TI0528A.	200:19C-1 Flame Sensor	Flare Tip	Thermocouple
RFLRE:19TI0528B.	200:19C-1 Flame Sensor	Flare Tip	Thermocouple
RFLRE:19TI0528C.	200:19C-1 Flame Sensor	Flare Tip	Thermocouple
RFLRE:19TI0528D.	200:19C-1 Flame Sensor	Flare Tip	Thermocouple
Analyzers			
RFLRE:19AI0520.	42" Line - Molecular Weight	42" Line - Upstream of Flare Stack Water Seal (C-1)	MW Indicator
RFLRE:19AI0586.	10" Line – Molecular Weight	10" Line - From U200 & U267	MW Indicator
RFLRE:19AI0501.	42" Line - Oxygen	42" Line - Upstream of Flare Stack Water Seal (C-1)	Oxygen Content Indicator
RFLRE:A2670	Net Heating Value Calorimeter, NHV RSR	42" Line - Upstream of Flare Stack Water Seal (C-1)	Calorimeter
RFLRE:A2671	Hydrogen Composition RSR	42" Line - Upstream of Flare Stack Water Seal (C-1)	H2 Analyzer

2.2.3.2 MP-30 Flare (S-398)

Flare System Flowmeters

MP-30 Flare (S-398) – Flare System Flowmeters				
Tag Number	***Description***	***Location***	***Type (e.g. sonic)***	***Range (X – Y scfm)***
Flare Gas Flow:				
RFLRE:19FI0584.	MP30 48" Line	48" Line - Downstream of Water Seal (F-604)	Ultrasonic Flowmeter	
RFLRE:19FI0584L.	48" Line - low range			0 - 2,000
RFLRE:19FI0584H.	48" Line - high range			0 - 35,070
RFLRE:19FI0585.	36" Line	36" Line - from Refinery Blowdown Line (F-2)	Ultrasonic Flowmeter	
RFLRE:19FI0585L.	36" Line – low range			0 – 2,000
RFLRE:19FI0585H.	36" Line – high range			0 – 120,000
RFLRE:19FI0580.		12" Line - From U200 & U267	Ultrasonic Flowmeter	
RFLRE:19FI0580L.				0 – 2,000
RFLRE:19FI0580H.				0 – 510 MSCFH
Purge Gas Flow				
RFLRE:19FIC0511.	Natural Gas Purge		Orifice Plate	0 - 930 MSCFD

MP-30 Flare (S-398) – Flare System Flowmeters				
Tag Number	***Description***	***Location***	***Type (e.g. sonic)***	***Range (X – Y scfm)***
Steam Flow				
RFLRE:2676	Steam to Flare RSR	Flare Tip	Ultrasonic	0 – 100 Mlb/hr

[1] Does not meet 12-11 accuracy requirements for all ranges. Utilized as a backup meter, when necessary.

Continuous Recording Instruments

MP-30 Flare (S-398) – Continuous Recording Instruments			
Tag Number	***Description***	***Location***	***Instrument Type***
Pressure			
R230:PI6014.	230F-600 Blowdown Drum	Upstream of MP30 Relief Blowdown Drum (F-600)	Pressure Indicator
RFLRE:19PI0584.	MP30 48" Line	48" Line - Downstream of Water Seal (F-604)	Pressure Indicator
Level			
R230:LIC654A.	230:F-604 MP30 Flare System Water Seal Make Up H2O Level	F-604 Vessel	
R230:LIC654B.	230F-604 MP30 Flare System Water Seal H2O Drain Level	F-604 Vessel	

MP-30 Flare (S-398) – Continuous Recording Instruments			
Tag Number	***Description***	***Location***	***Instrument Type***
RFLRE:19LI0509.	200:(C-602) Flare Stack Water Seal	MP30 Flare Stack (C-602) Water Seal	Water Seal Level Indicator
Temperature:			
RFLRE:19TI0584.	200:MP30 Flare Vapor Temperature	48" Line - Downstream of Water Seal (F-604)	Temperature
RFLRE:19TI0529A.	200:(C-602) NW Flare Pilot	Flare Tip	Thermocouple
RFLRE:19TI0529B.	200:(C-602) NE Flare Pilot	Flare Tip	Thermocouple
RFLRE:19TI0529C.	200:(C-602) SE Flare Pilot	Flare Tip	Thermocouple
RFLRE:19TI0529D.	200:(C-602) SW Flare Pilot	Flare Tip	Thermocouple
Analyzers			
RFLRE:19AI0584.	200:MP30 Flare Vapor Molecular Weight	48" Line - Downstream of Water Seal (F-604)	Molecular Weight Indicator
RFLRE:19AI0585.	200:MP30 Flare Vapor Molecular Weight	36" Line - from Refinery Blowdown Line (F-2)	Molecular Weight Indicator
RFLRE:19AI0580.	200:MP30 Flare Vapor Molecular Weight	12” Line - From U200 & U267	Molecular Weight Indicator
RFLRE:19AI0502.	200:MP30 Flare Oxygen	48" Line - Downstream of Water Seal (F-604)	Oxygen Content Indicator

MP-30 Flare (S-398) – Continuous Recording Instruments			
Tag Number	***Description***	***Location***	***Instrument Type***
RFLRE:A2674	Net Heating Value Calorimeter, NHV RSR	48" Line - Downstream of Water Seal (F-604)	Calorimeter
RFLRE:A2675	Hydrogen Composition RSR	48" Line - Downstream of Water Seal (F-604)	H2 Analyzer

Unit 200 Flare Gas Recovery Compressor (G-503)
See Attachment C and L for diagrams showing locations of meters and analyzers.

Flowmeters

Flare Gas Recovery Compressor (G-503) Flowmeters				
Tag Number	***Description***	***Location***	***Type*** ***(e.g. sonic)***	***Range*** ***(X – Y MMSCFD)***
Gas Flow:				
R200:FI_506B.	Flare Gas Recovery Compressor (G-503)	Downstream of Salt Water Exchanger E-510	Orifice Plate	0 – 4.64

Monitors and Instruments

Note: All setpoints and alarms are subject to change. These values may change as operational or safety optimization opportunities are identified. This list contains the values at the time of publication.

Flare Gas Recovery Compressor (G-503) Monitors and Instruments

Flare Gas Recovery Compressor (G-503) Monitors & Instruments				
Tag Number	***Description***	***Location***	***Att***	***Setpoint or Alarms***
Pressure				
R200:PI0509.	200:F-509 Separator Overhead	F-509 Separator Overhead	C	0.5 psig Alarm 0.0 psig – Action automatic unloading of compressor cylinders
R200:PI0513.	200:G-503 1st Stage	Downstream of 1st Stage	C	None
R200:PI0515.	200:G-503 2nd Stage	Downstream of 2nd Stage	C	None
R200:PI0514.	200:G-503 Frame Oil	Downstream of Frame Oil Filters	L	None
R200 – PAL 575	200: G-503 Frame Oil (Local Indication)	Downstream of Frame Oil Filters	L	Shutdown Compressor - < 16 psig
Temperature				
R200:TI0509.	200:F-509 Separator Overhead	F-509 Separator Overhead	C	Alarm – 150 ^{o}F
R200:TI0511.	200:G-503 Flare Gas Recovery Compressor 1st Stage	Downstream of 1st Stage	C	None
R200:TI0513.	200:G-503 Flare Gas Recovery Compressor 2nd Stage	Downstream of 2nd Stage	C	Alarm – 300 ^{o}F Shutdown - 350 ^{o}F

Flare Gas Recovery Compressor (G-503) Monitors & Instruments				
Tag Number	***Description***	***Location***	***Att***	***Setpoint or Alarms***
R200:TI0510.	200:G-503 Tempered Water	Upstream of Exchanger E-512	L	None
R200:TI0512.	200:G-503 Frame Oil	Downstream of Frame Oil Pump	L	None
Analyzer				
R200:AI0504.	200:G-503 Discharge Specific Gravity (SG)	Compressor Discharge	L	Alarm Low SG – 0.60 Alarm High SG – 1.12
R200 - AE503.	200:G-503 Compressor Discharge Oxygen Analyzer	Compressor Discharge	L	Alarm – 1.5% O_2
Level Indicator				
R200:L 509	200:F-509 Level Indicator (Local Indicator)	F-509 Low Pressure Separator	L	Level is monitored by Operator.
R200 – LAH 510	200:F-509 Level Shutdown (Local Indicator)	F-509 Low Pressure Separator	L	Shutdown Compressor – 30% Level
R200 – LAH 537	200:F-503A Level Shutdown (Local Indicator)	F-503A G-503 First Stage Suction Pulsation Dampener	L	Shutdown Compressor – 75% Level
R200 – LAH 538	200:F-503C Level Shutdown (Local Indicator)	F-503C: G-503 Second Station Suction Pulsation Dampener	L	Shutdown Compressor – 75% Level
R200 – LAH 541	200:F-503E Level Shutdown (Local Indicator)	F-503E: G-503 Second Stage Suction Knock Out Pot	L	Shutdown Compressor – 90% Level

2.2.3.3 Unit 200 Liquid Ring Flare Gas Recovery Compressors (G-540A/B/C)

Note: All data in this section is preliminary and subject to change. These values and meter numbers may change as operational or safety optimization opportunities are identified. The Compressor is undergoing a Process Hazard Analysis (PHA) at the time of the FMP update, which may result in additional changes. At this time all ranges and setpoints are being developed and thus are shown as pending.

See Attachment C and L for diagrams showing locations of meters and analyzers.

Flowmeters

Liquid Ring Flare Gas Recovery Compressor (G-540 A/B/C) Flowmeters				
Tag Number	***Description***	***Location***	***Type*** ***(e.g. sonic)***	***Range*** ***(X – Y MMSCFD)***
Gas Flow:				
FI-1573	Liquid Ring Flare Gas Recovery Compressor (G-540A, B, & C) Flow	Downstream of F-540 Gas Separator Drum	Orifice	0 – 6,000 MSCFD
Service Liquid Flow:				
FI-1544 (A) **FI-1545 (B)** **FI-1546 (C)**	Compressor Service Liquid Flow Indication, Alarm, & Shutdown	To Compressor	Orifice	0-200 gpm <u>Alarms:</u> Low Low 100 (SD) Low 110 gpm High 150 gpm

Monitors and Instruments

Note: All data in this section is preliminary and subject to change. These values may change as operational or safety optimization opportunities are identified. The Compressor is undergoing a Process Hazard Analysis (PHA) at the time of the FMP update, which may result in additional changes.

Liquid Ring Flare Gas Recovery Compressor (G-540 A/B/C) Monitors and Instruments

Liquid Ring Flare Gas Recovery Compressor (G-540 A/B/C) Monitors & Instruments				
Tag Number	***Description***	***Location***	***Att***	***Setpoint or Alarms***
Pressure				
PI-1541	High Pressure Alarm and Shutdown	Flare Gas to Compressor	C	Alarm High 115.3 psig Alarm High High 125.3 psig (SD)
PI-1543	Low & High Suction Pressure Alarm	Flare Gas to Compressor	C	Alarm High 18.5 psia Alarm Low 14.7 psia
PI-1881 (A) PI-1882 (B) PI-1883 (C)	Compressor Dual Seal Low Pressure Alarm	Compressor Seal	C	Alarm Low 50 psig
Temperature				
TI-1540	Suction Temperature Alarm and Shutdown	Compressor Suction	C	Alarm High 150 ^{o}F Alarm High High 170 ^{o}F (SD)
TI – 1547 (A) TI-1548 (B) TI-1549 (C)	Compressor Temperature Discharge Gas Temperature Indication, Alarm, & Shutdown	Discharge of Compressor	C	Alarm High 150 ^{o}F Alarm High High 170 ^{o}F (SD)
TAH-1545	Service Water Temperature Alarm	Service Water to Compressor	C	Alarm High 150 ^{o}F

Liquid Ring Flare Gas Recovery Compressor (G-540 A/B/C) Monitors & Instruments				
Tag Number	***Description***	***Location***	***Att***	***Setpoint or Alarms***
Analyzer				
VI-1541 (A) **VI-1542 (B)** **VI-1543 (C)**	Compressor Vibration Alarms	Connected to compressor	C	High Alarm 0.4 in/second High High Alarm 0.6 in/second (SD)
Level Indicator				
LI-1881 (A) LI-1882 (B) LI-1883 (C)	Compressor Dual Seal Low Level Alarm	Compressor Seal	C	Alarm Low 35%
LAHH-1543	Compressor Suction Liquid Level Alarm and Shutdown	Compressor Suction	C	Alarm Low 32%
LAHH-1540	Gas Separator Drum Liquid Level Alarm & Shutdown	F-540 Gas Separator Drum	C	Alarm High 85% Alarm High High 99% (SD) Alarm Low 15.2% Alarm Low Low 4.3% (SD)
LAH-1542	Gas Separator High Level Alarm	F-540 Gas Separator Drum Blowdown Side	C	Alarm Low 10%

2.2.4 Flare Monitoring Instrumentation Description

BAAQMD 12-11 and 40 CFR 63 Subpart CC identifies criteria for monitoring flare gas flow and supplemental gas. 40 CFR 63 Subpart CC added requirements for steam measurement and heating value of flare and supplemental gas. The instrument locations were selected in accordance with manufacturer guidelines and the requirements in 40 CR 63 Subpart CC, as applicable. Flare data is collected and recorded in the site data historian. Data is maintained for a minimum of five years.

2.2.4.1 Vent Gas Flow, Steam Assist and Supplemental Rate Monitoring

BAAQMD 12-11 and 40 CFR 63 Supart CC requires each affected flare to be equipped with a flow meter that provides a representative measurement of the total flow rate discharged to each flare. The flow rate data collected is used to determine if flaring events occur that exceed the RCA threshold of 500,000 scf in a 24-hour period.

RSR amendments to MACT CC (40 CFR Part 63), effective January 30, 2019, require subject sites to install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any flare supplemental gas used. This volumetric flow data along with other measured parameters will be used to determine compliance with the net heating value of flare combustion zone gas (NHVcz) at each flare.

The following standards for the vent gas flow meters are required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13:

- Must be located in a position that is representative of the total gas flow rate;
- Must have a flow sensor accuracy of +/-20% at velocities ranging from 0.1 to 1 foot per second and an accuracy of +/-5% for velocities greater than 1 foot per second.
- Must be maintainable online,
- Ensure that the readout of the moitored operating parameter is readout accessible onsite for operational control or inspection,
- Must continually correct for pressure and temperature and record flow in standard conditions.
- At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.
- Recalibrate the flow monitor in accordance with the manufacturer’s procedures and specifications which is annually.

Each flare uses an ultrasonic flow meter to continuously measure the flow rate to the flares. Each flow meter is manufactured according to the specifications in the rule, and the refinery has ensured that each flow meter is installed in a representative location of flare gas flow rate, thereby complying with the selection and installation of the flow meter. The following table summarizes the specifications of each flow meter in use.

Flare Flow Meter Specifications		
Meter No.	FLRE:FI520 (Main) – Waste Gas FLRE:FI586 (Main) – Waste Gas FLRE: FI585 (MP30) – Vent Gas (Waste & NG) FLRE:FI584 (MP30) – Vent Gas (Waste & NG)	FLRE:FI580 (MP30) – Waste Gas
Make	General Electric	SICK
Model	DigitalFlow™ GF868	MCUP-SNB3CE00000NSN
Type	Ultrasonic Flare Gas Flow Meter	
Range	0.1 fps to 328 fps	
Precision	Repeatability = ±1%	
Accuracy	±0.5% +/-20% at velocities ranging from 0.1 to 1 fps and +/-5% for velocities greater than 1 fps	

The meter configuration is a dual-channel bias-90 configuration with temperature and pressure corrected readings. The pressure and temperature readings are used to automatically correct the raw flow meter reading to standard condition flow rates and are reported to the Distributed Control System (DCS). Since the flow meter uses a dual-channel configuration (i.e., two sensors), no quarterly visual inspections of the meter are required. Each flow meter is recalibrated on an annual frequency in accordance with the manufacturer's specifications. The flow meter will be inspected during each calibration verification. Since the flowmeter has no moving parts and is constructed of materials designed to withstand the corrosive environment of the flare vent gas, the manufacturer does not recommend any further routine maintenance. In some cases, the meter includes natural gas purge, sweep or supplemental flow to the flare, in other cases it does not. Attachment C contains Process Flow Diagrams (PFDs) for each flare and their respective monitoring configuration. In cases where natural gas purge, sweep or supplemental flow is downstream of the Flare Flow Meter the purge meter is utilized in conjunction with the Flare Flow Meter to determine the Vent Gas.

Under 40 CFR 63.670, RSR requirements allow for mass flow monitors to be used for determining volumetric flow rate of assist steam. The refinery has installed necessary mass flow monitors to aid assist steam rate determination at each of its flares.

Steam Meter Specifications	
Meter No.	FLRE:FI2673 (Main Flare) FLRE:FI2676 (MP30 Flare)
Make	SICK
Model	FLOWSIC100 EX-S-RE
Type	Ultrasonic Mass Flow Meter
Range	0 – 100 Mlb/hr
Precision	-1 (shown in decimal)
Accuracy	+/- 2.5-5.0% of reading at range 0.3 m/s up to max value of measuring range

The following standards are required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13:

- ±5 percent over the normal range measured for mass flow.
- Record the results of each calibration check and inspection.
- Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

Under 40 CFR 63.670, RSR requirements allow for mass flow monitors to be used for determining volumetric flow rate of assist steam. The refinery has installed necessary mass flow monitors to aid assist steam rate determination at each of its flares.

The refinery has added the following natural gas meter for enhanced supplemental gas control and monitoring.

Supplemental Gas (Natural Gas) Monitoring	
Meter No.	FLRE: FI510 (Main Flare) – two range *MP30 flare NG is monitored with the Flare Flow meter*
Make	Rosemount
Model	3051 CD
Type	Differential Pressure with Orifice Plate
Range	Low Range: 0 – 1,689 MSCFD High Range: 0 – 3,120 MSCFD
Precision	-1 (shown in decimal)
Accuracy	+/- 5%

The following standards are required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13:

- ±5 percent over the normal range of flow.
- Record the results of each calibration check and inspection.
- Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

The refinery meter installations comply with all of the standards required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13. For instruments required by RSR details regarding the specifications of each vent gas, supplemental gas, and steam flow meters, including the precision, accuracy, calibration, maintenance procedures, and quality assurance procedures are maintained onsite in equipment databases. In addition, preventative maintenance is tracked via the work order database utilized by Phillips 66.

2.2.4.2 Heating Value Determination

As part of the Refinery Sector Rule (RSR) changes under 40 CFR 63 Subpart CC, there are new requirements for flares which include combustion efficiency standards effective beginning January 30, 2019. The standard requires that a determination of the Net Heating Value (NHV) of vent gas for each affected flare must be determined through prescribed methods via compositional monitoring of the vent gas. US EPA provided the options of a Calorimeter, Gas Chromatograph, and/or Grab Samples for compositional monitoring of the flare vent gas.

The refinery has chosen to comply with the new RSR NHV requirements at its flares by installing Calorimeters with a Hydrogen measurement module. . The Hydrogen measurement module is in place to provide for Hydrogen combustion correction as allowed in 40 CFR 63.670(l)(3).

The facility takes grab samples for flare activity as required by BAAQMD 12-11. Hydrocarbon species of the grab samples is determined in accordance to BAAQMD 12-11 . The refinery reserves the ability to use the hydrocarbon species results to determine Net Heating Value, as needed, if the calorimeter is not functioning.

Natural gas is utilized as supplemental gas which is metered independently in the Main Flare. In accordance to 63.670(j)(5) the heating value of 920 Btu/scf is utilized in addition to the heating value provided by the Calorimeter for the refinery waste gas. Daily gas chromatograph data is available by the Natural Gas utility supplier. The refinery reserves the ability to use the daily calculated Net Heating Value from the gas chromatograph speciated results.

The following table summarizes the specifications of the chosen calorimeter:

Calorimeter & Hydrogen Measurement	
Make	HOBRE
Model	WIM COMPAS
Type	Calorimeter – NHV Frontal Elution - H2
Precision	-1 (decimal)
Accuracy	+/- 1% of full scale

The following standards are required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13:

- ±2 percent of span for Net Heating Value.

- +/-2 percent over the concentration measured or 0.1 volume percent, whichever is greater.
- Calibration requirements should follow manufacturer's recommendations, at a minimum
- Specify calibration requirements in your site specific CPMS monitoring plan
- Temperature the sampling system to ensure proper year-round operation

The refinery meter installations comply with all of the standards required pursuant to 40 CFR 63, Appendix to Subpart CC of Part 63—Tables, Table 13. For instruments required by RSR details regarding the specifications of each vent gas, supplemental gas, and steam flow meters, including the precision, accuracy, calibration, maintenance procedures, and quality assurance procedures are maintained onsite in equipment databases. In addition, preventative maintenance is tracked via the work order database utilized by Phillips 66.

2.2.5 Pressure Relief Devices (PRDs) to Flares

All pressure relief valves/devices (PRV/PRD) are tracked in an electronic software tool. The software tool contains information including manufacturer, tag number, type, size, set pressure, orifice size and numerous other details. The tool is cross-referenced with the facility work order scheduling and tracking system known as SAP. The site also documents the design basis for all of the relief devices to the flares. The system contains the information from the software tool includes how the required relief rate is determined for each PRV. Attachment J of this document lists Pressure Relief Devices/Valves that are discharged to the flares.

PRV's are removed, inspected, tested, and recertified according to the API 510 Pressure Vessel Inspection Code. API 510, in conjunction with several other API inspection codes, dictates how the interval is established. In general, the intervals are coincident with a unit turnaround, but not always, with API 510 accounting for the difference. The facility utilizes the Risk Based Inspection (RBI) review procedure for determining inspection frequencies based on RV service and history. In addition to API 510 the facility follows the following codes, regulations, and standards at the site in regard to PRV design, inspection, and maintenance.

- ASME Boiler & Pressure Vessel Code, Section I for Power Boilers and Section VIII for Unfired Pressure Vessels.
- ANSI/ASME B31.3 Chemical Plant and Petroleum Refinery Piping Code
- API 510 Pressure Vessel Inspection Code
- API 520 Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries, Parts I & II
- API 521 Guide for Pressure-Relieving and Depressuring Systems
- API RP 526 Flanged Steel Safety Relief Valves
- API RP 576 Inspection of Pressure Relieving Devices

In addition to the PRV processes identified above the facility is required to conduct PHAs to identify and mitigate potential risk to personnel and/or equipment. These PHAs look at measures in place to prevent events with unintended consequences. Based on potential risk identified, as these PHAs are conducted mitigation to prevent unintended consequences are put in place. Thus, this mitigation employed following the PHA has a beneficial effect of preventing some unit upsets that could trigger use of PRVs vented to the flare. In addition, the refinery conducts Root Cause Analysis (RCAs) for various threshold triggering flare events and identifies required corrective actions to prevent recurrence. This also, when applicable, identifies measures to reduce the occurrence of PRVs venting to the flare.

The facility also employs applicable redundant prevention measures, at affected pressure relief devices onsite that can discharge to flares, that comply with requirements under 40 CFR §63.648(j)(3)(ii). These preventive measures are documented under various facility documentation like Process Safety Information, Operating Limits, Refinery Policies etc.

3.0 Reductions & Planned Reductions

3.1 Reductions Previously Realized (401.2)

Changes or Equipment in Place prior to 2003 which Prevent or Minimize Flaring

Due to economics and community concern, the refinery has a long history of flare minimization practices. The Flare Gas Recovery Compressor (G-503) was installed in the early 70's. Up until 2000 the facility utilized a ground flare that was located near I-80. When the flare was utilized the flame was very visible from the highway. Prior to 2000 the Refinery Management had expectations for Operations to increase facility reliability to prevent upsets and to develop a means to conduct Startups & Shutdowns with minimal flaring. Those practices remain in place today.

Another item of note is the existing Sulfur Recovery Unit system. The facility has three Sulfur Recovery Units (U235, 236, & 238) which can provide for significant redundancy. This has allowed the facility to experience only one instance of acid gas flaring in the past five years from a complete refinery shutdown.

In 1999, the Unit 200 Wet Gas Compressor (G-501) seal was upgraded to a dry seal system. Previously, the seal would fail every 12 – 24 months which required a seal replacement. The seal replacement would take approximately 5 – 6 days and flaring would occur throughout this period. After the dry seals were installed, the on-line performance of the Compressor significantly improved. The compressor has not experienced a seal failure since the seal upgrade. The upgrade has resulted in a reduction of approximately 4 - 6 MMSCFD of gas flared for approximately 5 days every 12 – 24 months.

Starting in 2003 weekly updates and quarterly Key Performance Indicators (KPIs) are reported & distributed with Flaring History to all Refinery employees. The content and distribution of the KPIs is described in Environmental Services Department (ESD) Policy and Procedure 1.1 “Environmental KPIs”. The KPIs issued show trends and causes for flaring events and other reportable environmental events. The KPIs helps reduce flaring by showing all employees this is important in that it is tracked and communicated.

Changes Made to Reduce Flare Emissions

June 2012 to July 2019

In accordance with 401.2, listed below are reductions that have been made to reduce flaring over the past 5 years. Many of the items listed are Management System improvements. Although some of these improvements are difficult to quantify, they have had a significant impact on minimizing flaring.

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
Procedures:	
1st Qtr 2013 (updated)	**Refinery Policy & Procedure (P&P) 6.05-05 "Flare Monitoring & Reporting"** - • Procedure created to communicate flare sampling, monitoring, & root cause analysis requirements. The contents of the procedure include Responsibilities for personnel at the refinery in respect to flare compliance activities. • Sets standards for accountability in regards to monitoring, reporting, and preventing recurrence. • Criteria for agency release reporting (i.e. CA OES, CCC HSD, BAAQMD, NRC, etc.) for flare events. • Summary of BAAQMD 12-11 flare monitoring requirements (e.g. video, flare flow, sampling), • Summary of various regulatory reporting requirements. • Criteria for incident investigation in respect to BAAQMD regulations and the Phillips 66 EPA Consent Decree. • Means to track flare events with P66 Corporate incident tracking system. This procedure reduces flaring by demonstrating to employees that those who have defined roles must follow the steps outlined in the procedure and that these activities are important. It also mandates expectation for consistent evaluation of flaring events & development of corrective actions to prevent recurrence.

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
3rd Qtr 2013 (updated)	**Refinery Policy & Procedure (P&P) 10.00-01 "Incident Investigation" & Incident Investigation Training** - P&P 10.00-01 establishes responsibilities, event triggers, and typical means for conducting incident investigations. The contents of the procedure include: • Definition of the types of incidents that can occur (i.e. minor, serious, major). • Responsibilities for employees that discover an incident and who must complete tasks in respect to incident investigations. • Establishes accountability. • Description of whom and when personnel should be notified of incidents. • Defines who should participate in an incident investigation. • Description of the investigation process. • How the findings of an incident investigation are reviewed. • How findings of an incident investigation should be communicated to employees and Phillips 66 sister refineries. • How corrective actions should be addressed. The existing procedure was updated to denote environmental related events requiring incident investigation. Flaring events are identified in the procedure. P&P 6-7 cross references P&P 5-1. This procedure reduces flaring by demonstrating to employees that those who have defined roles must follow the steps outlined in the procedure and that these activities are important. Without this procedure incidents which occur would not necessarily be investigated and addressed in a consistent fashion. The main value in flaring reduction is that this procedure requires that corrective actions be developed and addressed for incidents. To ensure good quality investigations are conducted the facility identified key personnel to receive incident investigation training. Training ensured that first reporting (basic who, what, when, where) captures critical initial information. The training also ensures that investigations receive the necessary level of investigation and get to defined root causes. Additional work is on-going to improve and maintain the quality of the investigations conducted.

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
Procedures:	
2nd Qtr 2013 (updated)	**Emergency Operating Procedure EOP-1 "Guidelines for Standard Public Address System Announcements" -** Enhanced Communication within the Facility when Flare Gas Recovery System Load Increases – For example, the facility Public Announcement system is currently used if an increase in the compressor load occurs. This requires process units to review their operations in order to find the cause of the increase and take actions to mitigate. This prevents some flaring events from occurring in that discretionary gases, such as nitrogen purges and hydrogen, sent to the flare gas recovery system can be scheduled around peak loading periods to maximize gases recovered. Coordination of these activities is done through Operators at various units and Shift Supervisors working together to coordinate their activities in respect to use of the flare gas blowdown system. This minimizes flaring by consciously identify periods in which the blowdown system can be utilized without overloading the flare gas recovery compressor. This results in less periods of flaring due to brief peak loading of the compressor. In addition to this process, the Public Announcement system is utilized during planned and emergency events as specified in some of the Unit 200 procedures (ESOP & NSOP-*various*-200) to improve equipment use and switching. For example, if the Flare Gas Recovery Compressor (G-503) is put into Wet Gas or Odor Abatement service the public announcement system will be utilized to notify plant personnel of the change in operation. Listed below is a partial list of some of the key procedures where the public announcement system use is referenced:

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
	<u>Normal Operating Procedures</u> • NSOP-001-200 Relief “U200 Table of Safe Operating Limits” • NSOP-306-200 “Light Ends Shutdown, Unit Running” • NSOP-704-200 “G-501 Compressor Shutdown & Clean-up” • NSOP-707-200 “G-503 Flare Compressor Planned Shutdown” • NSOP-709-200 G-503 Flare Compressor Start-up • NSOP-710-200 “Switching G-503 to Wet Gas Service” • NSOP-711-200 “Switching G-503 from Wet Gas to Flare Service” • NSOP-716-200 “Switching G-503 to Odor Abatement Service” • NSOP 717-200 “G-503 Flare Compressor Circulation” **<u>Emergency Operating Procedures</u>** • ESOP-700-200 “Loss of G-501 Compressor” • ESOP-701-200 “G-503 Compressor Failure”
3rd Qtr 2013	**Loss of Emergency Gas Flow to Air Liquide (REOP-25-OPS)** - A new Refinery Emergency Operating Procedure (REOP) was developed in response to the June 10, 2013 flaring event after loss of RFG-A to Air Liquide. This procedure will help to reduce the flaring of sour flare gas by improved management of the RFG-A gas at Unit 240 Plant 3 and it should also reduce the overall flaring time for this type of event with improved management of the Flare Gas recovery compressors.
2nd Qtr 2011	**Loss of Hydrogen (REOP-21-OPS)** Hydrogen is a critical refinery utility. Loss of 3rd party of site produced hydrogen can result in unit upsets. This procedure helps guide user, typically Shift Superintendent, to make the necessary operational moves in a sequenced fashion to reduce impacts to the refinery. These operational moves help reduce potential rate of flaring that can occur with hydrogen loss.
1st Quarter 2018	**Activity on the Refinery Flare/Blowdown Systems (REOP-12-OPS)** A multi-step procedure was developed to help assist the facility Shift Superintendent coordinate between affected units when there is refinery flare activity and how to quickly respond in order to mitigate flaring in an efficient manner. The procedure incorporates the requirement to review the “Flare System Rundown List” when there is flare activity or heavier than expected load on the Flare Gas Recovery Compressor(s) but the cause is not immediately known.

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
On-Going	**Environmental Operating Limits (EOL) Standard**. The Rodeo Refinery implemented a new Phillips 66 Corporate Standard designed to enhance existing refinery Environmental monitoring practices. As part of the EOL standard, Environmental, Technical Services, and Operations personnel reviewed site permit, regulatory and other legal requirements and created a new document for Operators and Operation Supervisors to ensure Environmental compliance. When applicable, pre-alarms were developed to alert Operations in order to execute pre-defined corrective actions to avoid non-compliance and flaring incidents. The program is reviewed periodically and updated, as necessary. The EOL table includes flare limits and appropriate response to potential flaring activity above allowable limits.
On-Going	**Reliability Operating Limits (ROL) Standard.** Similar to the EOL Standard referenced above, Phillips 66 maintains a Corporate Standard designed to enhance existing reliability monitoring practices. ROLs are established for a suite of equipment in order to identify parameters that have potential to have an impact on the reliable operation of units and/or equipment. This includes equipment such as flare compressors, utility compressors, critical pumps, etc. Once the ROLs have been identified alarms have been developed to alert Operations when to initiate action based on defined criteria. This standard helps prevent unplanned equipment and unit shutdowns or damage which typically corresponds to improved environmental compliance and performance.
Equipment:	
1st Quarter 2019	**EPA Refinery Sector Rule (RSR) 40 CFR 63 Subpart CC Flare Combustion Efficiency Upgrades –** all affected refinery flares are required to ensure compliance with sections 63.670 and 63.671 of 40 CFR 63 Subpart CC. This requires high accurate monitoring of steam flow to the flares as well as prescribed net heating value (NHV) determination for vent gas to the flare. Flare activity occurring post January 30, 2019 must comply with the 63.670 combustion efficiency standard of 270 Btu/scf. The Rodeo Refinery has made upgrades to the steam measurements and controls as well as securing a new NHV monitor.

Changes Made to Reduce Flare Emissions (June 2012 – July 2019)	
Year Installed or Implemented	***Equipment Item Added, Process Changed or Procedure Implemented***
Processes:	
1st Qtr 2011 - 2013	**Unit 110 Hydrogen Plant Startups and Shutdowns –** changes have been made in how Unit 110 startups and shutdowns, when conditions warrant, to minimize flaring. For example, a shutdown takes place and human entry is not required, the unit may be purged with plant Nitrogen rather than hot, pumped Nitrogen. This allows for the Nitrogen to slowly be swept into the blowdown system, allowing for the Fuel Gas Recovery Compressor to remain operating. For some shutdowns the amount of flaring has been eliminated vs. a previous average period of of 5-1/2 hours. Unit startups have also been reduced from a period of approximately 2-1/2 hours in comparison to the previous duration of 5 hours. Throughout 2011 and 2012 efforts to minimize Unit 110 related flaring has continued by examining steps related to startup and shutdown activities. In 2013 a procedure NOP-206-110 was developed to allow for U110 startup with minimal flaring. This is partially done utilizing natural gas feed at a low rate to minimize potential flaring.
On-Going	**Flare System Rundown List (R-065)** – A checklist was developed for looking for possible sources (lines and monitoring tags) at operating units which may be contributing high base load to the flare compressors and/or directly to the flare. This checklist is to be used by Shift Superintendents, Head Operators, and Unit Supervisors to pinpoint and locate higher than normal flows.
3rd Quarter 2014	**Unit 110 Hydrogen Plant Control Scheme Upgrade** the control scheme for Unit 110 was updated to allow for a better transition between a 10-bed to 5-bed Pressure Swing Adsorber (PSA) operation. When a need to reduce the number of operating PSA Hydrogen purification beds from 10 to 5 the feed to the unit will also automatically adjust. This will reduce the amount of Hydrogen that enters into the blowdown system and will reduce or eliminate flaring associated with this operational transition.

3.2 Planned Reductions (401.3)

The table below summarizes the actions currently planned to effect further reductions in refinery flaring.

Planned Actions for Reducing Flaring

Planned Actions for Reducing Flaring	
Planned Date of Installation/ Implementation	***Equipment Item to be Added, Process to be Changed or Procedure to be Implemented***
<u>Procedure:</u>	
Equipment	
<u>Phased 2006 – 2013</u> • 2006 – MP30 (complete) • 2009 – Sulfur Plant (complete) • 2009 – UK (complete) • 2011 – U200/ U267/U250 (complete) • 2014 - U110 & SPP (complete) • 2015 – U100 & Bulk (complete) *(completion dates listed)*	**Construction & Operation of Central Control Room (CCR)** The CCR has been built and currently contains the controls and boardmen for all the process, utility and bulk movement units. The Boardmen are the Operators that oversee the unit operation and provide direction to Outside Operators. The Boardmen were housed in Control Rooms at their individual units The CCR brings all the Boardmen together in one large control room. There is an inherent value in having the Boardmen housed in one Control Room that will minimize flaring. Improved communication will occur and better awareness of each unit's impact upon another unit's operation will occur. In addition, optimization by Operations Supervision will be simplified when the unit controls are housed in one Control Room. An example of this benefit is that if one unit is nitrogen purging a vessel which will add loading to the U200 G-503 Flare Gas Recovery Compressor the Boardman can immediately talk to the Unit 200 Boardman about whether or not additional loading can be handled. As the purging is taking place the two Boardmen can work closely together to monitor the impact of purging and provide immediate feedback as to the impact of the activity on the Compressor. Adjustments can be made much more quickly to manage the activity. This enhanced coordination will reduce in flaring.

Planned Actions for Reducing Flaring	
Planned Date of Installation/ Implementation	***Equipment Item to be Added, Process to be Changed or Procedure to be Implemented***
Phased 2006 – 2013 • 2006 – MP30 (Complete) • 2009 – Sulfur Plant (complete) • 2009 – UK (complete) • 2011 – U200/ U267/U250 (complete) • 2014 – U110 & SPP (complete) • 2015 – U100 & Bulk (complete) *(completion dates listed)*	**Controls Modernization** – a series of controls modernization projects were completed in 2015. Listed below are the benefits of the modernization projects in respect to flare minimization. • Provides for enhanced diagnostic tools (i.e. graphics of unit operation are much more visible and easy to follow) in units where Distributed Control Systems (DCS) are not currently in place (MP30 & Sulfur Recovery Units). • Reduction of control system instrumentation failures due to upgrade from old, pneumatic technology. This will result in much better reliability of the controls. • Increases unit stability and minimizes unit upsets. • Improves operator performance by incorporating Abnormal Situation Management practices such as alarm management and graphic guidelines. Alarm management is a philosophy which prioritizes alarms and minimizes the amount of alarms an operator must respond to in an abnormal situation. This prevents an operator from being overloaded with alarms and helps the operator focus on the immediate issues which must be remedied. • Use of human factors in information processing in order to communicate information in a proven, consistent, simplified, meaningful way. Early event detection to reduce abnormal situations which might cause an upset. Installation of state of the art Safety Instrumented Systems (SIS) that will minimize spurious trips. Overall, the Controls Modernization will reduce flaring by minimizing upsets that can occur with the current controls in place. Improving the way that operators interface with controls allows them to prioritize their response to abnormal situations. This can result in more rapidly mitigating an unusual situation and minimizing overall impacts. One example would be by upgrading field tags (which are monitoring devices for operating parameters such as pressure or temperature, currently only visible in the field) to a tag which can be monitored in the control room. For example, if an equipment shutdown occurs and the parameter which shut the equipment down is a field tag, the modernized control system will more rapidly pinpoint the cause of the shutdown. The upgraded field tag would now be able to be seen rapidly by the Board Operator which will assist in restarting the piece of equipment more rapidly. This will reduce flaring.

Planned Actions for Reducing Flaring	
Planned Date of Installation/ Implementation	***Equipment Item to be Added, Process to be Changed or Procedure to be Implemented***
1st Quarter 2021 County Land Use Permit undergoing re-approval process [1] [1] *Re-approval process following Superior Court decision to void previous approval due to EIR deficiencies*	**Propane Recovery Project –** The Authority to Construct for this project application was issued by BAAQMD on March 18, 2015. The purpose of the project is to recovery propane and butane from the refinery fuel gas (RFG). Another aspect of the project is to remove a portion of the sulfur compounds from the remaining Refinery Fuel Gas (RFG). From a flaring standpoint, this project is beneficial in reducing overall volume of Refinery Fuel Gas. The propane and butane will be replaced by natural gas provided by PG&E. Because it is relatively easy to reduce the amount of natural gas being imported, the likelihood of flaring due to fuel gas imbalance will be reduced. In addition, by reducing the concentration of sulfur in fuel gas this removes some of the restrictions on where fuel gas can be routed which further helps to minimize and reduce periods of potential fuel gas imbalance.
4th Qtr 2019	**Unit 240 D-411 Hydrogen Re-routing During Unicracker Plant 2 Shutdown (SFE 17-103)** – Currently when the Unicracker Plant 2 shuts down there can be excess mixed hydrogen in the hydrogen header. Mixed hydrogen contains hydrogen produced from catalytic reformers and PSA high purity hydrogen. Currently, when there is excess mixed hydrogen it is sent to blowdown and then on to the site Flare Gas Recovery Compressors (FGRC) where it can be potentially recovered and utilized as fuel gas. If there is too much hydrogen concentration in the gas routed through the FGRC this can result in compressor shutdowns due to poor gas quality. A FGRC shutdown would result in the flaring of mixed hydrogen and sour recovered gas. High levels of hydrogen in recovered fuel gas can also be a problem for heater operation which demands minimum fuel heating value. This project will re-route the potential discharge of this mixed hydrogen from blowdown to the Unit 240 F-201 relief header which goes directly to the flare rather than to the FGRC and fuel gas. Thus, if the system pressure dictates that mixed hydrogen must be pressure relived it will do so directly to the flare. This will help reduce the total volume of material sent to the flare and reduce the emissions of Sulfur Dioxide (SO_2) if flaring does occur.
Processes:	
On-going	**Improved Incident Analysis Investigation** – Continue to complete required 12-12 Root Cause analysis and analysis triggered by internal incident investigation drivers. Investigations and corrective actions identified will continue to address issues that may result in flaring if not otherwise addressed. The root cause analysis requires that the facility find the actual cause of flaring, down to a single part that may have failed in some instances. The 12-12 analysis also requires the facility to identify changes that can be made to prevent flaring and list those in the root cause analysis submittal to BAAQMD. This results in the facility taking action to prevent recurrence of flaring events. For example, some of the recent root cause analysis have identified equipment upgrades that should be made, additional training to be conducted, equipment repairs, etc.

Planned Actions for Reducing Flaring	
Planned Date of Installation/ Implementation	***Equipment Item to be Added, Process to be Changed or Procedure to be Implemented***
Permit Application Submitted 12/2011 Target Completion - Awaiting BAAQMD and EPA Decision	**Fuel Gas Combustion Sulfur Dioxide Emissions** –A permit application was submitted to BAAQMD to obtain new Sulfur Dioxide (SO2) limits for the Steam Power Plant (SPP) via permit modification. This would allow greater percentage of refinery fuel gas to natural gas to be fired in the turbines. By revising the SPP emission limits it is possible that a large portion of flaring during periods of fuel gas imbalance could be minimized while reducing overall combustion emissions. Historically fuel gas imbalance occurred during major Unicracker turnarounds when 30% of fired duty sources are shutdown. Discussions were previously held with BAAQMD permit engineers in 2007 to review the benefits and potential permitting mechanisms for repermitting SPP. Numerous discussions and responses have been provided to BAAQMD in respect to the permit application and permit revisions. BAAQMD has been provided the necessary supporting information and must approve and finalize the permit in order for the facility to implement this item. Phillips 66 petitioned the U.S. EPA in April, 2014 for an official applicability determination regarding whether this change would trigger NSPS. BAAQMD is currently awaiting the response from EPA prior to finalizing their decision whether or not to approve the permit.
On-going	**Flare Activity Review –** Soon after a reportable flaring event occurs an overview of the event is communicated between site management to quickly review likely causes and means to prevent recurrence.
Maintenance:	
On-going	**G-503/G-540 Flare Gas Recovery Compressors** - this practice began more than 5 years ago and continues to date. Approximately every 18 months, in association with a major unit turnaround, the G-503 Flare Gas Recovery Compressor is taken out of service for a major overhaul. The purpose is to maintain critical equipment associated with the compressor in order to prevent unplanned failures. This practice minimizes overall downtime for the compressor. The work is scheduled with a major turnaround since gasses produced at the facility are at reduced rates and many fuel gas consumers are out of service. Without this maintenance it is more likely that the compressor would experience unplanned failures during periods when high gas volumes are being produced. The unplanned failure repair is of longer duration because the personnel and equipment must be assembled without advanced planning. In many cases, diagnosis must be performed to determine the failure and this can take considerable time. Whereas, planned maintenance prevents many of these types of failures from occurring. As with regular maintenance on a vehicle, this maintenance performs a similar purpose. Now that the new Liquid Ring Flare Gas Recovery Compressor has been installed all flare gas recovery compressors will be maintained on a routine basis yet it will be done when the spare compressor(s) are in operation which will further reduce overall flare emissions.

4.0 Prevention Measures (401.4)

4.1 "Major" Maintenance Activities (401.4.1)

This section discusses refinery maintenance and turnaround activities, outlines measures to minimize flaring during both preplanned and unplanned maintenance activities. A description of flaring that occurs during major maintenance activities is included in this section and in the section titled "When Flaring is Likely to Occur" in accordance to 401.4.1. As required by 401.4.1 a review of flaring associated with major maintenance has been conducted and is referenced below. The measures taken to prevent flaring during portions of major maintenance activities are included in the section titled "Measures to Minimize Flaring During Preplanned Maintenance".

4.1.1 Refinery Maintenance and Turnaround Activities

Maintenance activities often result in a higher than normal flow of material to the flare gas recovery system. In order to maintain process equipment, the first step is to clear the process equipment and associated piping of hydrocarbons, before the system is opened to the atmosphere, for both safety and environmental reasons, including compliance with BAAQMD Regulation 8 Rule 10, (Process Vessel Depressurization). How this is accomplished depends on the physical properties of the hydrocarbons to be removed (vapor pressure, viscosity) and on the process details of the equipment that is to be maintained.

The first step is to recover as much of the hydrocarbon as is possible by transferring it to a process unit that is not in the part of the refinery that is being prepared for maintenance. For example, liquid hydrocarbons can be pumped to tankage or another process system; gases under pressure may be depressurized to another process unit. Heavy hydrocarbons that are viscous at ambient temperatures are often displaced from the equipment to be maintained using lighter hydrocarbons, e.g. diesel type material. This material can then be pumped from the equipment.

Although depressurization and pump-out can be used to remove the bulk of the hydrocarbon from the equipment, they leave some residual material. Following pump-out or depressurization to other process equipment, the next step in decommissioning typically requires a low-pressure location that has the ability to accept a wide range of hydrocarbon materials in order to avoid putting these materials to the atmosphere. The flare gas header is the only location within the refinery that meets these criteria. Equipment items containing materials that are gases at ambient temperature and pressure are often vented to the flare gas recovery system so that the hydrocarbon can be recovered as fuel gas. To free the equipment of hydrocarbons following depressurization, they can be purged using an inert gas such as nitrogen. Alternatively, nitrogen can be added to the equipment increasing the internal pressure. The resulting mixture of nitrogen and hydrocarbon can then be released to the flare header, reducing the pressure in the equipment. Steam can be substituted for nitrogen in some cases, but not for processes that need to be kept dry in order to avoid corrosion or catalyst damage, or for some other reason.

For equipment containing liquids, often steam or nitrogen are used to "blow" the liquid to the flare header. The liquid hydrocarbon and condensed steam are separated from the vapor phase and returned to the refinery's recovered oil system and to wastewater treatment either at the unit knockout drum or at the flare knockout drum. Nitrogen with hydrocarbon vapor continues on to flare gas recovery. Once the bulk of the liquid hydrocarbon has been displaced, the flow of steam or nitrogen is continued to remove any residual hydrocarbon by vaporization. Steam can be more effective for heavier materials as it increases their volatility by increasing temperature. Proprietary solvents such as "Zyme-flow" are sometimes used in aqueous solution for removal of residual hydrocarbons. When aqueous solvents are used, they are typically circulated in the equipment and then treated.

Although these procedures eliminate hydrocarbon emissions related to equipment opening, they require a high volumetric, high velocity, steam or nitrogen flowrate in order to be effective. This high flowrate of inert gas can create several sets of circumstances where flare gas recovery is not feasible. These problems relate either to the change in fuel gas composition (increased molecular weight or temperature) or to the increase in volumetric flowrate.

In addition to an increase in flare gas average molecular weight from higher than normal nitrogen flowrate, there is also the potential for much lower than average molecular weight gas from increased flow of hydrogen. There are many process and reactor systems within a refinery that contain gases with a high hydrogen content. When this equipment is decommissioned by depressurization to the flare gas header, there can be a sharp decrease in the flare gas average molecular weight.

Effect of Flare Gas on Downstream Equipment

Gas composition affects the equipment in the flare gas recovery system. Specifically:

- High nitrogen content can impact heaters, boilers and the flare gas compressor.
- Hydrogen and other low molecular weight gases impact flare gas compressor performance.
- Steam impacts knock out drums and compressors.

High flows of nitrogen from equipment purging leads to a much higher than normal inert content in the recovered flare gas, greatly reducing its fuel value (measured as Btu/scf) and increasing its molecular weight. Reciprocating compressor (G-503) increase the pressure of a constant inlet volumetric flowrate of gas. For a given volume of gas, an increase in molecular weight creates an increase in its mass. This increases the work that the compressor has to do to compress the gas, overloading and potentially damaging the machine.

For a reciprocating compressor, the compression ratio (ratio of outlet pressure to inlet pressure) is high enough that more than one stage of compression is needed. The temperature of the gas increases as it is compressed. The gas is cooled between stages in order to control the temperature increase. Operation of a reciprocating compressor with a feed stream that has a molecular weight outside of the range for which it was designed (e.g. high hydrogen content) can lead to a temperature increase exceeding the design limitations of the machine. Flare Gas Compressor (G-503) is shutdown in order to protect it from failure that could be caused by a decrease in molecular weight.

The Liquid Ring compressors are expected to have a wider range of operating conditions. The compressors and associated control system will have enhanced monitoring in comparison with the existing Reciprocating Compressor. There will still be limitations on the type of gases that should be recovered and utilized in the fuel gas system (i.e. high volumes of hydrogen potentially impacting Btu values).

Additionally, if low Btu flare gas is transferred to the fuel gas header, the lower fuel value can have the effect of reducing combustion efficiency, as the combustion device burners are designed to operate with fuels that have higher heat content per cubic foot. In extreme cases, the heating value of the gas can be reduced by dilution with nitrogen to the point of extinguishing the burner flame. This creates the potential for unburned fuel to accumulate in the heater or boiler, potentially leading to an explosion when it is re-ignited. NFPA 85 – Boiler and Combustion Systems Hazards Code and NFPA 86 Standards for Ovens and Furnaces warn against this possibility.

A major advantage of using steam to clear hydrocarbons from equipment is its elevated temperature; however this can be a disadvantage with respect to flare gas recovery. When the distance the gas must travel to reach the flare gas compressor is large, (the flare header is long), the gas will cool, and much of the steam will condense and be removed as water at the knock-out drum. However; with a shorter flare line or a long-duration steam out event, the temperature of the flare gas at the flare gas compressor can be elevated significantly. If the temperature of the flare gas stream at the inlet to the flare gas compressor exceeds machine limits, the gas must be diverted away from the compressor inlet in order to avoid mechanical damage.

Summary

Each of the situations described above potentially leads to the need to divert gas produced during refinery maintenance away from the flare gas recovery compressor and to a flare. This is a necessary result of maintenance procedures which have been adopted to minimize the release of hydrocarbons to the atmosphere during equipment opening. The need to divert gas is driven by the quantity and composition of the gases produced during equipment shutdown and startup.

Major maintenance activities can result in flaring, as discussed above. A review of maintenance-related flaring from 2000 to 2006 at the Phillips 66 San Francisco refinery in Rodeo has been completed. Due to the requirement to install flowmeters and report flare emissions to BAAQMD the data from September 2003 to date is the most accurate for this review. Subsequent flaring taking place during equipment startups and shutdowns are being examined as part of the Turnaround Planning Flare Minimization Process and causal analysis being conducted.

Based on the review there were means of further reducing and/or eliminating flaring that were identified. Included below is a summary of the measures identified and rationale for the acceptance or rejection of the concept:

Major Maintenance
Prevention Measure Evaluation

This is a list of prevention measures that were identified based on the 5-year look back of Major Maintenance activities. Attachment H is a summary of all flaring events and is grouped by category. Based on the 5-year look back the following types of flaring were identified for elimination:

- Flaring associated with Hydrogen Unit Startups/Shutdowns (H2 SU/SD)
- Flaring due to G-503 Flare Gas Recovery Compressor Planned Maintenance (G-503 PM)
- General Flaring Associated with Major Maintenance (.e.g. nitrogen purging, steaming, etc.) (General)

Major Maintenance – Prevention Measure Evaluation

Measure Description	Schedule for Implementation	Rationale to Support Schedule	Type of Flaring that would be Reduced or Eliminated	Rationale for Rejecting Measure	Section Reference *(for more details)*
Addition of Unit 110 Hydrogen Vent	• Dec. 2006	Installation of a vent which will allow a small stream of purified hydrogen to be vented.	H2 SU/SD	n/a	3.2
Odor Abatement/Flare Gas Recovery System Optimization	• October 2008 – Construction Start • August 2009 (completed)	A set of 3 Liquid Ring Compressors were installed in order to provide redundant and extra capacity for the Flare Gas Recovery compressor. This will eliminate some flaring events that have historically occurred by having additional flare gas recovery service. A separate odor abatement compressor was installed which will provide further reliability for the odor abatement system.	G-503 SU/SD G-503 Brief Peak Loading	Completed	3.2
Turnaround (T/A) Planning Procedure	4th Qtr 2006	Being coordinated with submittal of Flare Minimization Plan.	H2 SU/SD G-503 PM General	n/a	4.1.3
Shutdown & Startup Activity Extension	4th Qtr 2006	This will be included as part of the T/A Planning Procedure. In some cases flaring may be eliminated or minimized by extending the period	General	To be included as part of T/A Planning Procedure process.	4.1.3

Major Maintenance – Prevention Measure Evaluation					
Measure Description	**Schedule for Implementation**	**Rationale to Support Schedule**	**Type of Flaring that would be Reduced or Eliminated**	**Rationale for Rejecting Measure**	**Section Reference** *(for more details)*
		that a unit is going through shutdown or startup. An example would be to nitrogen (N_2) purge equipment at a lower rate so the G-503 Flare Gas Recovery Compressor can handle the excess N_2. More importantly, the safest operating conditions for a unit are when it is out of service or when it is running at normal conditions. The transition period, which occurs during startup and shutdown, requires special attention and procedures. Equipment placed under these conditions experience temperature and pressure changes which can result in hydrocarbon leaks. Due to these factors it is necessary to minimize the duration of transition periods.		This will not be utilized in each case due to transitional activity concerns.	
Rate Reduction / Unit Shutdowns	4^{th} Qtr 2006	This will be included as part of the T/A Planning Procedure process. In some cases flaring may be eliminated or minimized through reducing rates or shutting down units. The implications of shutting down a unit must be examined for each case. For example, shutting down additional units may result in more fuel gas imbalance (i.e. production of more gas then can be consumed). The refinery units are interrelated so shutting down one or two units will result in impacts to other units. In some cases a number of units must be shutdown in association with a particular unit. In order to properly shutdown units they must be depressured and purged. This typically results in flaring. So, the shutdown of associated units	General	To be included as part of T/A Planning Procedure process. It is not beneficial to use this for all situations as described in the previous column.	4.1.3

Major Maintenance – Prevention Measure Evaluation					
Measure Description	**Schedule for Implementation**	**Rationale to Support Schedule**	**Type of Flaring that would be Reduced or Eliminated**	**Rationale for Rejecting Measure**	**Section Reference** *(for more details)*
		doesn't reduce flaring in all cases and must be evaluated for the overall benefit on a case by case basis. Rate reduction is typically only of potential value if refinery is out of fuel gas balance. See Section 4.1.2 for the steps taken to mitigate fuel gas imbalances, including rate reduction. Some units may be an overall fuel consumer so reducing rate may not be helpful. The benefits need to be examined on a case by case basis.			
Implementation of Prevention Measures Identified during Causal Analysis Reporting	3rd Qtr 2005	Prevention Measures are identified during the required BAAQMD flare event Causal Analysis reporting. These measures are then implemented to reduce flaring. Note: General programmatic prevention measures identified will be listed in this section during Annual updates. Equipment specific prevention measures have been added to Attachment H.	Various	n/a	3.1
Identification of Cause of Small (<500,000 SCFD or <500 lb SO2) Flaring Activity	1st Qtr 2007	Conduct regular meetings with Operation personnel who are responsible for the flare operation to identify causes of all flare activities.	Various	n/a	3.1
Storage, Treatment, Recovery Scenario 1 – Addition of New 1.5	n/a	n/a	G-503 PM (portion)	Determined not to be cost effective.	4.2.2.1

Major Maintenance – Prevention Measure Evaluation					
Measure Description	**Schedule for Implementation**	**Rationale to Support Schedule**	**Type of Flaring that would be Reduced or Eliminated**	**Rationale for Rejecting Measure**	**Section Reference** *(for more details)*
MMSCF/D Compressor			General		
Storage, Treatment, Recovery Scenario 2 – Addition of New 6.0 MMSCF/D Compressor	n/a	n/a	G-503 PM General	Determined not to be cost effective. However, a set of three new Flare Gas Recovery Compressors were installed in conjunction with the Clean Fuels Expansion Project.	4.2.2.1
Storage, Treatment, Recovery Scenario 3 & 4 – Addition of New High Pressure Storage Sphere, Compressor, & Amine Treater	n/a	n/a	H2 SU/SD G-503 PM General	Determined not to be cost effective. Technological, operability, and safety feasibility not yet determined. It is likely that upon further study cost effectiveness will be further diminished. Operability and feasibility of safe operation of such a system may also pose a challenge.	4.2.2.1

Section 4.1.2 contains a list of measures that are currently in practice for reducing flaring.

From this review it is clear that one of the greatest potentials for achieving further cost-effective reductions in flaring lie in maintenance planning with flare minimization as a goal coupled with the existing goals of safety and minimizing production impacts due to extended downtimes. The essential component of any plan that satisfies maintenance needs while minimizing flaring is that it must mitigate or eliminate the conditions described in the sections above that make recovery of flare gas impossible. In practical terms this means taking a series of actions specific to the unit being decommissioned to limit the rate at which flare gas is generated and maintain its temperature and composition within a range acceptable for transfer via a flare gas compressor and for use in the fuel gas system. Concepts for accomplishing this are discussed in the section following.

4.1.2 Measures to Minimize Flaring During Preplanned Maintenance

In accordance with 401.4.1 in regards to feasible prevention measures that can be used to minimize future flaring: (including that related to scheduled process unit turnarounds and immediate near-term shutdowns) are listed below. Numerous prevention measures are utilized to prevent flaring from occurring during portions of major maintenance events. The information is organized by process unit and by topic. There are also some general measures listed that are used at most units, when applicable. Refer to Attachment E for list of unit names and numbers. It is noted that although prevention measures are routinely employed, as explained in the previous section, all flaring cannot be eliminated due to gas quality and quantity issues associated with major maintenance activities.

<u>Hydroprocessing (U228, U229, U230, U231, U240-2, U244, U248, U250)</u>

Hydroprocessing units are depressurized to hydrogen recovery, or other lower pressure locations , and only after this are they depressurized to flare gas recovery, reducing the load on the flare gas recovery system. This prevents flaring by minimizing load on the flare gas recovery system and decreases the period of time in which flaring occurs during venting activities.

Following depressurization, the remaining hydrocarbon is removed by increasing the pressure in the equipment with nitrogen and then depressurizing it to flare gas recovery multiple times. Doing this quickly helps with mixing, which improves removal of hydrocarbon from the vessel so that fewer cycles are needed. This minimizes the volume of low quality gasses that are sent to the flare.

Depressurization of the unit to the flare gas recovery system is staged in order to minimize exceeding the capacity or quality parameters of the system in order to maximize the time in which the flare gas recovery compressor is on-line. The longer the flare gas recovery compressor is on-line the less flaring that occurs.

Gases are recirculated using the hydrogen recycle compressors as the reactors cool. When the equipment is cooled and at low pressure, nitrogen pressurization and release steps are used to clear hydrocarbons. Hydrogen-containing streams are directed to the hydrogen plant. Use of hydrogen recycle for cooling and cleaning minimizes the need for nitrogen which, when utilized, typically results in flaring.

U250 - A high pressure hydrotreater design is used to avoid flow to the flare by containing the process during loss of utilities. Without this design, additional volume of materials would be sent to the flare during loss of utilities. See Section 3.1 for more details on elements of this design.

<u>Reformer (U231, U244)</u>

The timing of the steps involved in the regeneration cycle are controlled and the venting / depressuring rate limited to be within the capacity of the compressors. This minimizes the total vent stream that must be sent to the flare.

Delayed Coker (U200)

The delayed coker drum cooling cycle time is coordinated with other activities to prevent exceeding the Flare Gas Recovery Compressor capacity.

Fractionation Units (Various units, throughout refinery)

Vents from depressurization of fractionation units are recovered using the flare gas compressor system rather than being routed to the flare, when capacity is available or gas quality allows. This minimizes flaring by reducing the volume of gasses that must be sent to the flare.

Compressor (U200 Flare & Blowdown System)

Compressor Maintenance

In some instances, the flare gas recovery compressor (G-503) is placed in wet gas recovery compressor service (G-501) if the wet gas compressor is expected to be offline. This minimizes the total amount of gas flared. A greater volume of gas can be recovered by placing G-503 directly in Wet Gas service rather than directing the Wet Gas into the blowdown system. Recovering higher rates of gas reduces the volume recovered.

Flare gas compressors are maintained during planned unit shutdowns, to improve reliability during periods of normal operation. A planned shutdown provides an opportunity to do maintenance while flare system load is lower.

In the future, when the redundant new Liquid Ring Flare Gas Recovery Compressors are operational planned maintenance scheduling will be optimized and staggered to minimize and/or prevent flare gas recovery outages for compressor maintenance.

Regular preventative maintenance of flare gas compressors, as described further in Section 3.2, is used to improve their reliability.

Maintenance is also conducted on compressors based on critical monitoring (i.e. vibration, temperature, load) results.

Flare System Monitoring

Flare Gas Recovery Compressor load is monitored to identify & mitigate higher than normal baseline load. High loads are mitigated by identifying the source and making reductions. For example, if a PRV is venting to blowdown then the responsible unit will be identified and directed to make adjustments to prevent the PRV from venting.

The flare gas recovery compressor is monitored when maintenance is being conducted at other units that will cause the compressor to be taken off-line. The purpose is to minimize the amount of compressor downtime in order to protect the compressor and minimize the total time the compressor is shutdown and reduce overall flaring.

Plant personnel who oversee flare gas recovery systems have been instilled with an improved understanding. The operators monitor flare gas compressor load to check for high load or load changes, record instances of flaring and potential causes, take action to minimize flaring, and notify Shift Superintendents when flaring occurs. This results in conscious management of the flare system to minimize flaring.

Flow and/or temperature measurement as a means of indicating flow in each flare header is used to identify and eliminate sources of flow to the flare gas header. Indication of flow during periods when flow is not expected is a direct indication of flaring. As described above, operators respond to flaring events by attempting to track the source and working with the Shift Superintendent to take action to make reductions or eliminate flaring.

The monitoring parameters available for the Liquid Ring Compressors will be more robust and provide more on-line indication of changes in flare gas quality. This enhanced monitoring will likely assist in the optimization of compressor on-line performance.

On-line diagnostic tools are utilized to monitor flows to the flare in order to minimize flaring duration. See Section 3.1 "Operational Improvement – Monitoring" for more details on how these tools reduce flaring.

When higher than normal flare gas recovery compressor loads are detected announcements are made throughout the refinery in order to proactively identify and address the source of gases. See Section 3.1 Emergency Operating Procedure EOP-1 "Guidelines for Standard Public Address System Announcements" for more details.

Fuel Gas Scrubbing

Gases collected by the flare gas compressor are scrubbed whenever possible. This includes periods of fuel gas imbalance and periods when the compressor capacity is exceeded but the compressor is still operational. This results in reduced sulfur dioxide emissions from the flare.

Sulfur Recovery Units (U235, 236, & 238)

The refinery has three sulfur recovery units operating in parallel. During periods of maintenance the load is shifted from one unit to the others. Thus, no flaring is necessary during unit startups or shutdowns. Additionally, sulfur load can readily be reduced by decreasing sour water stripping. The Refinery has not historically experienced acid gas flaring during sulfur plant startups & shutdowns or upsets.

General Measures (used at various units, as applicable)

Liquid Vessel Cleanup

Chemical cleaning is used to so that cleanup is faster, minimizing the time needed for steam out. Chemical cleaning works similar to using dish soap on greasy dishes in that cleaning time and rinse water is minimized. Thus, in practice overall time in which steaming must occur is minimized, thus minimizing flaring. Chemical cleaning is primarily used in units where there is a high volume of residual oil and solids in equipment and piping. Chemical cleaning must be balanced with wastewater treatment plant capabilities.

Depressurization

Separate flare gas headers are in place at the Unicracker Complex for the Reactor section and Hydrogen Plant so that some gases produced during maintenance, startup, and shutdown can be directly routed to the flare. This minimizes the volume of gases sent to the flare during maintenance activities since it provides a separate system from the refinery blowdown system. This allows a portion of the refinery gasses to be recovered while only those from the Unicracker are sent to the flare.

Pressure Relief

Routine maintenance of PRDs, consistent with API 510, is used to minimize "routine" flow to the flare gas header. The purpose of the maintenance is to ensure the PRDs are operating properly at the appropriate set points and not relieving prior to the intended set point. Proper operation of PRDs provides a safe operation, reduces the base load and allows the system to better able to handle flow peaks during maintenance or other periods where there is additional flow in the blowdown system.

Source Reduction

If there are indications of increased base load to the flare gas compressor efforts are taken to identify and mitigate or minimize the source of gasses. This is done by identifying the flare header affected by use of monitoring parameters, as available, such as flare header flow meters, pressure and temperature indicators.

Shutdown/Startup Planning & Scheduling

A specific plan will be developed to minimize flaring during each turnaround, as each is unique. Specific actions depend on which parts of the unit are being brought down and which other units are down at the same time. Note: Historically this has taken place for major turnarounds, this will be expanded to minor turnarounds as well.

Specific "flare planning" has been conducted in respect to major turnarounds.

Plans have been prepared to insure there will be a viable fuel balance during each time period during the shutdown.

The length of the shutdown has been extended in some cases to allow equipment to be purged at lower rates that can be handled by the flare gas recovery system. Extension of shutdown length will be considered as part of the turnaround planning procedure referenced in Section 2. There are limitations to this activity. The safest operating condition for a unit is either when it is out of service or when it is running at normal conditions. The transition period, which occurs during startup and shutdown, requires special attention and procedures. Equipment placed under these conditions experience temperature and pressure changes during the transition period which can result in hydrocarbon loss. Due to these factors it is necessary to minimize the duration of transition periods.

Rate Reductions and Unit Shutdowns at interrelated units occur to balance inventory. This will be included as part of the T/A Planning Procedure process referenced in Section 2. The implications of shutting down a unit must be examined for each case. For example, shutting down additional units may result in more fuel gas imbalance (i.e. production of more gas then can be consumed). The refinery units are interrelated so shutting down one or two units will result in impacts to other units. In some cases a number of units must be shutdown in association with a particular unit. In order to properly shutdown units they must be depressured and purged. This typically results in flaring. So, the shutdown of associated units doesn't reduce flaring in all cases and must be evaluated for the overall benefit on a case by case basis.

Rate reduction is typically only of potential value if refinery is out of fuel gas balance. Again, the big picture needs to be examined. Some units may be an overall fuel consumer so reducing rate may not be helpful. The benefits need to be examined on a case by case basis.

Load shed planning is used to keep the fuel gas system in balance as units come up/down. Following the turnaround, any flaring that did occur is reviewed and a list of lessons learned is developed in order to minimize flaring during future turnaround events. Note: This is a minimization effort that is being instituted in a more rigorous manner as part of this FMP. This consistently applied review will help establish successful flare minimization practices that can be utilized in the future.

Shutdown activities are staged to keep the rate to the flare gas compressor low. This will be considered on a case by case basis as part of the turnaround planning procedure referenced in Section 2 which addresses flare minimization.

Turnarounds are scheduled so as to bring some units down every year, so that not all units are down at any one time.

Turnarounds are scheduled to minimize downtime associated with the unit and to provide a window for conducting preventative maintenance in order to promote equipment reliability. Conducting turnarounds on a regular basis prevents unplanned shutdowns that can lead to long periods of flaring if the necessary equipment is not available to quickly remedy a failure.

The duration between turnarounds is being extended over time as technology improves in order to minimize production impacts. This also results in minimizing flaring over long periods of time (i.e. 5 – 10 year windows). The reason this reduces flaring is that the number of turnarounds in a 10 year period is reduced if the duration between turnarounds is extended. Eliminating one or two turnarounds in a 10 year period will eliminate the flaring associated with the startup and shutdown activities. The duration between turnarounds is being extended due to improvements such as longer catalyst life, better unit monitoring, better metallurgy, enhanced inspection technology and procedures.

Shutdown and Startup Execution

Equipment is purged slowly to avoid overloading flare gas recovery system capacity. The minimum purge rate that can be achieved is limited by the need to prepare the equipment for maintenance. This will be evaluated as part of the turnaround planning procedure referenced in Section 2.

Cleanup activities are cascaded so that large amounts of nitrogen are not routed to the flare at any one time. If all equipment was purged with nitrogen simultaneously this would likely overwhelm the flare gas recovery compressor. By cascading the purging, this allows the flare gas recovery compressor to recovery gasses to blowdown during a longer period of time, thus minimizing overall flaring since the compressor has been kept on-line for a longer period of time.

Steam is used instead of nitrogen for equipment clearing, as much of the steam condenses reducing the load on the flare recovery system. Steam is typically used in cases where there are not equipment vacuum limitations (e.g. piping, small equipment). Vessels typically have vacuum limitations. During steamout the peak flow to the flare gas recovery system is minimized by monitoring the steam rate and cutting back if the rate is too high. This does not eliminate all flaring associated with steamout procedures but minimizes the total amount of flaring.

The molecular weight of the flare gas is monitored, so that it is diverted away from the flare gas compressor when approaching outside of parameters that it can handle or that is suitable for combustion in unit heaters and boilers. This minimizes flaring by optimizing the period in which the compressor is on-line while also protecting the compressor from an equipment failure. Feed and product compressors are used to recycle material during startup until product specifications are met, allowing flaring to be avoided. The alternative would be to send gasses that have run once-through the reactors directly to blowdown. This minimizes the load to the flare gas recovery system and eliminates the potential for flaring.

Communication Measures

There is coordination from operator to operator and coordination within the shift organization so that the flare gas compressor load is not exceeded. The operators call to check on compressor operation before initiating actions that increase vent load.

Fuel Gas Balance

The fuel balance is adjusted to avoid flaring. This is done by examining the fuel gas balance which contains fuel producers and consumers. Depending on the environmental, safety and process constraints, operational changes are made dependent on which units have the most impact to the balance and the most flexibility. Reductions in fuel consumption or increases in consumption are attempted at numerous locations in order to get the facility back into fuel gas balance.

Steps taken to prevent fuel gas imbalances include and are generally included in the order of potential impact are:

- Minimize or cease butane vaporization to fuel gas.
- Increasing fuel consumption at operating heaters.
- Increasing production (i.e. fuel consumption) at Co-Generation plant.
- Operating steam turbines rather than electric drivers for pumps and compressors.
- Adjust the fuel supply at the Co-Generation plant to back out purchased natural gas and use more refinery fuel gas.
- Adjusting the severity of unit operations to affect the rate of gas production.

- Reducing process unit rates to decrease fuel gas generation.

The Refinery is also reviewing an application of a permit modification to address the short term SO_2 limit at the Co-Generation plant that restricts fuels gas consumption. Removing that restrictive limit will significantly reduce flaring from a fuel gas imbalance.

If a fuel gas imbalance does occur gasses are typically scrubbed for hydrogen sulfide removal. Excess clean gasses are then flared while additional measures are taken to mitigate the imbalance.

<u>Reliability</u>

The reliabilities of ancillary systems which can lead to flaring if they trip have been improved, reducing flaring. See the “Maintenance Excellence Philosophy” portion of Section 4.3.2.1 for more details of the facilities reliability practices.

Incident investigations, as further described in Section 3.1 and 3.2, are utilized to determine root cause of failures and determine appropriate corrective actions to prevent recurrence.

Maintenance is conducted on compressors based on critical monitoring (i.e. vibration, temperature, load) results.

Preventative maintenance is conducted on critical pieces of equipment (pumps, compressors, etc) throughout the refinery to prevent failures. The benefits described for Flare Gas Recovery Compressors in Section 3.2, preventative maintenance conducted on critical equipment serves a similar purpose. Planned maintenance prevents failures. Equipment failures can often lead to flaring if a unit experiences an upset or must be shutdown. By conducting preventative maintenance, failures can be prevented which reduces flaring.

4.1.3 Turnaround and Maintenance Flare Minimization Planning Tool

A planning tool has been developed and will be used to minimize flaring associated with planned turnaround and maintenance events, incorporating the minimization concepts outlined above. The means in which it will be utilized is presented in Attachment F. Listed below is an overview of the elements contained in the procedure:

- Establishing a timeline for conducting the initial evaluation of when flaring may occur prior to the turnaround;
- Scoping of the flaring that is expected to occur;
- Checklist which has a list of elements which should be considered in respect to flare minimization techniques;
- Post turnaround review of flaring which occurred.
- Documentation of lessons learned during the turnaround & successful minimization techniques utilized.
- Incorporation of lessons learned into appropriate shutdown, operating procedures, facility documents.

This process will minimize flaring by requiring more planning to address flaring that may occur during a unit shutdown and turnaround. It will also cause personnel associated with turnaround activities to develop means to alter their work in order to take action to minimize flaring. Lessons learned will be captured and used for future turnarounds in order to continue efforts to minimize and/or eliminate flaring. See Section 3 **Turnaround Planning Flare Minimization Procedure** discussion for more detail.

4.1.4 Measures to Minimize Flaring During Unplanned Maintenance

There are occasions, primarily as a result of equipment malfunction, where a relatively immediate decision is made to shut down a block of the refinery, typically within a period of hours, allowing very little time for specific planning. In these cases, although the maintenance planning tool can still be used, it is often not possible to make the adjustments necessary to minimize flaring to the same extent as is possible when the shutdown is planned in advance. Despite this, there are many actions that can be taken to minimize flaring even when there is very little advance notice. For these cases, the refinery utilizes general procedures that have been developed to minimize flaring during all maintenance events, as shown in the attached flowchart. Although there is less of an opportunity for scheduling turnaround activities so as to insure that there will be a home for all of the gas generated at each step of the process, many of the same general principles apply when the decision to bring the unit down is immediate.

4.2 Gas Quality/Quantity Issues for Each Flare (401.4.2)

This section discusses when flaring is likely to occur due to gas quality/quantity issues, systems for recovery of vent gas, and options for recovery, treatment and use of flare gas in accordance with 401.4.2

4.2.1 When Flaring is Likely to Occur

Releases of vent gas to the flare result from an imbalance between the quantity of vent gas produced by the refinery and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds) and utilized as fuel gas. Situations that can lead to flaring can be grouped together based on similarity of cause. These general categories, including specific examples of events which fit into each category, are outlined and discussed below as required by 401.4.2 in respect to flaring that may reasonably be expected to occur due to issues of gas quantity and quality:

4.2.1.1 Maintenance, Turnaround, Startup, and Shutdown

Generally, in order to maintain either an individual equipment item or a block of refinery equipment, it is necessary to remove it from operation and clear it of process fluids. Examples include:

- Unit shutdown
- Working on equipment
- Catalyst change
- Plant leak repairs
- Compressor system repairs (planned and unplanned)
- Unit Startup

<u>Fuel and Hydrogen Gas Balance</u>

All of these activities of necessity impact refinery operations in a variety of ways. In order to minimize the risk of flaring, there must, at all times, be a balance between producers and consumers of fuel gas. When either a block of equipment or an individual equipment item is removed from service, if it either produces or consumes gases, then the balance of the fuel gas system is changed and adjustments are necessary to bring the system back into balance. If the net change in gas production/consumption is large and adjustments in the rate at which gas is produced/consumed by other units cannot be made quickly enough, then flaring results.

Flaring also occurs during Hydrogen Plant startups, shutdowns, or when a downstream hydrogen user experiences a sudden outage. As previously described, flare gas recovery compressors cannot operate with high volumes of hydrogen in the system without sustaining damage. When a hydrogen plant has been shutdown it typically is shutdown with a hydrogen consumer. In order to properly startup the consumer unit the hydrogen must first be available. Therefore, hydrogen plants are started up initially and may not have an outlet for all the hydrogen being produced. If a vent is not available, the hydrogen is sent to the flare gas recovery system if the system can handle minor volumes, otherwise it is sent to the flare. Hydrogen is also utilized for downstream equipment sweeping, thus the hydrogen plant is typically shutdown after the downstream unit. Thus, for similar reasons to startup there can be hydrogen containing streams sent to the flare system. If a hydrogen consumer suddenly shuts down, in order to minimize overall facility impacts, the hydrogen plant is typically kept running, rates may be reduced, but excess hydrogen flared until the downstream unit is restarted. Specific examples of this effect and fuel gas balance issues are listed below:

- Fewer locations that can accept the gas due to equipment/units out of service
- Hydrogen plant startup/shutdown
    - Including Excess Hydrogen production following startup or unit shutdown
    - Temporary flaring of off-spec hydrogen during startup
    - Planned & Unplanned shutdowns can result in flaring
    - Planned & Unplanned shutdowns of the third party plant can result in flaring.
- Unicracker Complex turnaround (i.e. numerous combustion devices shutdown)

Equipment Preparation for Maintenance

Additionally, in order to clear hydrocarbons from equipment in a safe and orderly fashion so as to allow it to be maintained, a variety of procedures must be used. Many of these necessary procedures result in changes in the quantity and quality of fuel gas produced. For example:

- Depressurization of equipment
- Pressurization of equipment with nitrogen to remove hydrocarbon resulting in low fuel value (high nitrogen content) gas which cannot be used with burners designed for "normal" fuel gas, as there can be NOx production and flameout concerns with low Btu gas.
- Steaming provides an efficient means for removing hydrocarbon clingage from equipment but the effects of steam (high temperature, condensation production) can result in the need to shutdown flare gas recovery compressors.

See the "Refinery Maintenance and Turnaround Activities**"** section for more details in regards to the reasons for flaring during equipment preparation for maintenance.

Preventative Maintenance, On-Line Planned Maintenance, Equipment Upgrades, Changes

In order to prevent unplanned failures preventative maintenance (PM) is conducted at varying schedules. Typically, PM is conducted to minimize production and/or environmental impacts by grouping PM activities together. Additionally, equipment upgrades occur periodically or changes may be made to improve existing systems. During equipment upgrades/changes pieces of equipment may be required to be taken out of service for brief periods of time to ensure worker safety and/or allow for equipment access.

Flare Gas Recovery Compressor Maintenance –

Major Maintenance - typically conducted in conjunction with the Unicracker Complex turnaround in order to minimize environmental impact (i.e. less gas being produced while the Unicracker Complex is shutdown). The purpose of the PM is to maintain the compressor in order to minimize unplanned failures. This results in better on-line efficiency. Unplanned failures typically require more downtime due to time needed to diagnose the failure and then acquiring the necessary parts to make repairs.

Minor Maintenance – Based on on-going monitoring conducted on the compressor, see Recurring Failure section for more details, minor maintenance is conducted to replace parts or equipment which may fail or is not operating per the design. Purpose of the maintenance is to minimize and control downtime by preventing an unplanned, uncontrolled failure which may result in increased downtime. Additionally, the maintenance also can restore the compressor capacity and prevent flaring if the compressor is not functioning up to the equipment design.

Refinery Relief and Blowdown System Maintenance – Periodic maintenance is required on sections of the relief and blowdown systems (e.g. process vessels, drums, flare water seals, flare tips, etc.). This maintenance can include periodic, required metallurgical equipment inspections as well as preventative maintenance cleaning and replacement of components. These activities are required to prevent unplanned shutdowns which might incur long repair periods of not performed proactively.

Miscellaneous PM, Equipment Upgrades, Changes

Flare Gas Recovery System Maintenance - Construction tie-ins to the flare system, instrument changes, electrical upgrades, new equipment installations could require equipment to be taken out of service. This might result in flaring in order to isolate equipment and then also during equipment startup.

Equipment Upgrades / Changes - are made periodically to improve existing systems. This may require various pieces of equipment to be temporarily taken out of service. Portions of operating units or individual pieces of equipment may be taken off line for preventative maintenance or repairs. This can result in flaring during the clearing of equipment and flaring when equipment is put back in service.

On-Line Maintenance - Water washing of U244 D-506 and U231 D-105 Reformate Stabilizer is conducted periodically. The procedure is managed in order to minimize loading to the flare gas recovery system but there are periods when flaring may occur during this procedure.

4.2.1.2 High Base/Continuous Load

Although flaring is often the result of a sudden, short-term imbalance in the flare/fuel gas system, it is made more likely when the gap between the capacity of the flare gas recovery system and long term average flow to the flare header is reduced. Examples of base load to the flare header include:

- Leakage of relief valves
- Low pressure equipment vented to flare header, e.g. tower overhead systems
- Delayed coker depressurization
- Low pressure tankage or odor sources vented to flare header via blower or compressor
- Hydrocrackers and reformers at end of run with elevated gas production rates
- Accumulation of small actions each of which results in production of flare gas
- Seasonal issues with cooling water temperature resulting in increased rates to flare header
- Temporary re-rerouting of gases from other systems such as odor abatement to fuel gas recovery in order to prevent system overpressure.
- Feed quality issue resulting in temporary increased base load.

In cases of this type of flaring when the flare gas compressor is still operating the gasses recovered by the compressor will continue to be scrubbed for hydrogen sulfide removal at Unit 233.

4.2.1.3 Reduced Consumption of Fuel Gas

Treated flare gas may be flared during supply/demand imbalance. If flaring is to be minimized, it is necessary to balance fuel gas producers and consumers in the refinery. Refinery modifications that can change the fuel gas balance so as to make flaring more likely include:

- Energy efficiency projects that reduce fuel gas consumption
- Fuel gas imbalances can occur when fuel consumers (e.g. heaters, turbines) are shutdown and more gas is being produced then can be consumed.
- Fuel gas imbalances can occur when the third party Hydrogen Plant conducts planned or unplanned maintenance on feed filters and knock out drums.

4.2.1.4 Upset/Malfunction

An imbalance in the flare gas system can also result from any of a series of upsets or equipment malfunctions that either increase the volume of flare gas produced or decrease the ability of the fuel gas handling system to accommodate it. Examples include:

- Leaking relief valves, PRV malfunction
- Relieving relief valves
- Equipment plugging
- Loss of a major compressor (e.g. Wet gas compressor)
- Loss of flare gas compressors, including but not limited to:
    - Reciprocating compressor seats overheating from high nitrogen or hydrogen content

  - o Fuel gas with low specific gravity (due to Hydrogen), or high heat of compression resulting in overheating
  - o High inlet temperature to flare gas compressor
  - o Monitored safety/protective parameter (e.g. vibration) triggered shutdown.
  - o General mechanical problems inherent in the operation of rotating equipment.
  - o High liquid level.
  - o Equipment failure resulting in loss of compressor efficiency.
- Loss of other compressors (e.g. odor abatement, recycle hydrogen)
- Loss of a utility (steam, air, cooling water, power)
- Loss of air fins or condensers
- Failure of instrumentation, valve, pump, compressor, etc. to function as designed.
- Fuel quality upsets
- Hydrogen plant Pressure Swing Adsorption (PSA) operational changes (e.g. switching from 10 bed to 8 bed operation).
- Hydrogen plant PSA valve leaks resulting in a unit upset.
- Hydrogen may be sent to the flare system when there is a supply/demand imbalance.
- Unplanned/sudden shutdown of 3rd party Hydrogen Plant.
- Equipment failure which results in an immediate or controlled unit shutdown (e.g. charge pump failure)
- Feed quality issue resulting in unit upset. (e.g. wet feed, lighter than typical feed)
- Control system failures resulting in either unit shutdowns or unit not operating as efficiently in manual operating mode.
- The unit Hazard and Operability (HAZOP) studies contain more specific listings of potential causes of equipment malfunctions and upsets which may lead to flaring.

4.2.1.5 <u>Emergencies</u>

Equipment failures and operational issues that result in equipment overpressure, typically leading to relief valves opening to the flare system, are classed as emergencies. Emergency flaring events are severe instances of upsets or malfunction. Emergencies are further defined in BAAQMD 12-12.

- Line leak, fires due to leaking flanges, etc. can result in emergency unit shutdowns in which material from units is quickly sent to the flare.
- Unit Hazards and Operability Studies (HAZOPs) and Process Hazards Analysis (PHA) also reference emergency conditions which may lead to flaring. These studies are a systematic evaluation of the hazards involved in the process. PHAs are required for initiation of a process, for major equipment/operating changes, and at least once every five years after that. One of the values of PHA's is to identify potential hazardous and develop means for mitigating hazards before they occur. For example, one of the ways to conduct this evaluation is to take unit piping and instrument diagram (P&ID). The consequences of failure of pieces of equipment (e.g. on a pump if flow is lost, flow is increased, flow is decreased) are discussed and the mitigation in place is reviewed. Where improvements should be made they are identified and tracked to completion. See Section 4.3.2.1 for more details about PHAs.

4.2.1.6 Miscellaneous

- Undetermined Cause - in some cases the cause of flaring cannot be determined. Typically, this is during minor flaring events (<500,000 scfd). Systems have been setup to try and pinpoint the cause of all flaring events, most events are traced back to a source but there are instances when a direct cause cannot be determined.

- Natural Gas Purge – flaring can occur if there is a spike in the natural gas purge flow. One of the ways this may occur is if the natural gas purge valve is opened too quickly or at a rate greater than typical flow. This results in the brief flaring of excess purge gas.
- False Flow Meter Reading – as previously described to BAAQMD, many parameters (e.g. water seal level, flare line pressure, flare tip cameras) are utilized to determine whether or not flaring has actually occurred. In some cases flow may be detected by the meter, for example due to thermal expansion, but not all other parameters indicate that flaring has occurred. This is a common issue due to the sensitivity of the ultrasonic flow meters.

4.2.1.7 Other Causes

There are many potential causes of flaring, some of which are exceedingly difficult to totally eliminate, despite careful planning and system design.

4.2.2 Vent Gas Recovery Systems

As required by 401.4.2 the following sections contain an audit of the vent gas recovery, storage, and treatment capacity. In addition, an evaluation for installing additional recovery, storage, or treatment equipment to recover portions of gases periodically sent to the flare.

Refinery unit operations both produce and consume light hydrocarbons. Most of these hydrocarbons are routed directly from one refinery process unit to another. Refineries are constructed with a network of flare headers running throughout each of the process units in order to allow collection and safe handling of any hydrocarbon vapors that cannot be routed directly to another process unit. The hydrocarbon vapors are collected at low pressures in these flare headers. These gases are recovered for reuse by increasing their pressure using a flare gas compressor system. The compressed gases are typically returned to the refinery fuel gas system for use in fired equipment within the refinery. Any gas not compressed and sent to the fuel gas system is routed to a flare so it can be disposed of safely by combustion under controlled conditions. A typical flare gas system is shown in:

See Attachment G. In order to recover flare gas for use in the fuel gas system, three criteria must be met. First, there must be sufficient flare gas compressor capacity. Second, there must be sufficient gas treating capacity. Finally there must either be available storage volume or a user (e.g. fired heater) with a need for the gas. If any of these conditions are not met, then the gas cannot be recovered into the fuel gas header.

Existing Systems for Vent Gas Recovery

Within the Phillips 66 San Francisco Refinery at Rodeo, CA, the systems that currently exist for recovery of vent gas are described by the table below.

Flare System	Vent Gas Recovery Capacity (MM scfd)	Storage Capacity (MM scf)	Scrubbing Capacity for Vent Gas (MM scfd)	Total Gas Scrubbing Capacity (MM scfd)
Main Flare & MP30 Flare	4.75	None	None	35 [1]

[1] The facility does not have a scrubber for gases sent directly to the flare. The flare gas recovery system typically sends gases to U233 for H_2S removal and then sends these gases to fired sources. The capacity listed above includes the total capacity of the scrubbing system.

The Phillips 66, San Francisco Refinery vent gas recovery system does not include any dedicated capacity for storage of fuel gas or vent gas. However, on a continuous basis the refinery optimizes the refinery fuel gas system of producers and consumers to maximize the capacity available for treatment and reuse of recovered gases by employing the following strategies:

- adjusting the sources of fuel that are made up to the fuel gas system including imported natural gas, and butane;

- adjusting the operations of units that produce fuel gas range materials including at times reducing severity of operations to reduce fuel gas production if it would put the refinery in a flaring situation;

- adjusting the refinery profile for consumption of fuel gas by ensuring the cogeneration unit is at its maximum capacity (within constraints on exporting power), shifting rotating equipment to turbine drivers (which operate with steam generated in the fuel gas fired boilers), and at times reducing the throughput of processing units to minimize gas production. There are limitations to this activity. For example, the cogeneration unit has a sulfur dioxide (lb/hr) limit. The cogeneration unit utilizes a fuel mixture of refinery fuel gas (sulfur containing) and natural gas (nearly nil sulfur). As the ratio of refinery fuel gas is increased the units start approaching their sulfur dioxide limits. The amount of fuel gas burned in facility heaters is limited by permit conditions and energy efficiency constraints.

- When possible, the usage of fuel gas can be increased for brief periods of time to mitigate or prevent flaring.

4.2.2.1 Options for Recovery, Treatment and Use

To address the requirements of Regulation 12 Rule 12 (401.4), the Phillips 66, San Francisco refinery at Rodeo, CA has considered the feasibility of further reducing flaring through additional recovery, treatment, and/or storage of flare header gases, or to use the recovered gases through other means. This evaluation considers the impact these additional systems would have on the volume of flared gases remaining in excess of what has already been recovered (as noted in the previous section), and the associated mass flow of hydrocarbons emitted after combustion in the flare control device.

A typical flare header is connected to both a flare gas recovery system and to one or more flares. Normally all vapor flow to the flare header is recovered by a flare gas recovery compressor, which increases the pressure of the flare gas allowing it to be routed to a gas treater for removal of contaminants such as sulfur and then to the refinery fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressor(s), the treater(s), and/or the fuel gas system end users flows to a refinery flare so it can be safely disposed of by combustion. Therefore, in order to reduce the volume of gas flared, three essential infrastructure elements are required: sufficient compressor capacity to increase the pressure of the gas to the point where it can be used in the refinery fuel system, sufficient storage volume to dampen out the variation in volumetric flowrate to the flare gas header, and sufficient capacity in treating systems to condition the gas (primarily by removal of sulfur) for use in the fuel gas system.

Options for storage of flare gas are analogous to those for storage of other process gases. Gases can be stored at low pressure in expandable gas-holders with either liquid (water) or dry (fabric diaphragm) seals. The volumes of these systems expand and contract as gas is added or removed from the container. Very large vessels, containing up to 10,000,000 cubic feet of gas can be constructed by using multiple “lifts”, or stages. Gases can also be stored at higher pressures, and correspondingly lower volumes, in steel bullets or spheres. The optimal pressure vessel configuration depends on system design pressure and total required storage volume.

For any type of gas storage facility, selection of an acceptable site and obtaining the permits necessary for construction both present difficulties. Despite the refinery’s demonstrated commitment and strong track record with respect to safe handling of hazardous materials, the surrounding community can be expected to have concerns about any plan to store large volumes of flammable gas containing hydrogen sulfide and other sulfur compounds. Safety concerns are expected to impact site selection as well, with a relatively remote location preferred. Modifications to the recovery, storage and treating of refinery flare gases are subject to the provisions and approval of federal and local regulations including Process Safety Management (PSM), Contra Costa County Industrial Safety Ordinance (ISO), and California Accidental Release Prevention Program (CalARP). Although the objective of the project would be a reduction in flaring, there are expected to be multiple hurdles along the path to a construction/land use permit.

Flare gas treating is used to condition flare gas for use as fuel in the refinery fuel gas system. Treatment is focused on removal of sulfur compounds, with some systems improving fuel value by removing carbon dioxide as well. A range of technology options exist, most of which are based on absorption of acid gases into a “lean” amine solution (MEA, DEA, MDEA, DGA) with regeneration of the resulting “rich” solution by stripping at lower pressure. In order to recover additional fuel gas it is necessary to have sufficient capacity to match the capacity of gas treating systems to the peak flowrate of the flare gas requiring treatment.

In order to assess the potential effect of additional flare gas recovery, a hypothetical design for an upgraded system was developed. The impact that this system would be expected to have on hydrocarbon emissions, based on the refinery’s recent flaring history, was then evaluated. Results of this evaluation are provided for three system capacities corresponding to the rate of flow of additional flared gases that could be recovered, the modifications required to achieve that recovery, and the estimated total installed cost for the additional equipment needed for the increase in recovery. The budgetary level (order of magnitude) cost information provided in this section has been developed based on total installed cost data from similar installations where available, otherwise vendor quotes in combination with standard industry cost estimation procedures have been used to estimate system cost.

An evaluation was conducted for the Phillips 66, San Francisco Refinery in Rodeo, CA. In order to conduct the analysis a summary of historical flaring was prepared. Flaring events were categorized in order to determine feasible means for reducing flaring through storage, recovery, and treatment. See Attachment H for summary of categorized, historical flaring. The period of 2004 – 2006 was utilized to determine general trends. The data for 2005 was utilized to quantify potential costs and benefits of additional storage, recovery, and/or treatment.

Based on the data review it was determined that four cases should be examined. The cases include the following scenarios:

- Case 1 – Installation of Small Compressor (1.5 MMSCF/day) to enhance existing compressor recovery during peak loading.
- Case 2 – Installation of Large Compressor (6.0 MMSCF/day) to eliminate minor compressor loading events and some flaring events which occur during brief Flare Gas Recovery Compressor (G-503) preventative maintenance periods.
- Case 3 – Installation of high pressure storage sphere, installation of large compressor, and addition of amine treater. Value of this case would be to eliminate all events listed in Case 2 as well as some events which are quality driven (e.g. high Nitrogen & Hydrogen) due to equipment purging.
- Case 4 – Similar to Case 3 with a higher percentage of the volume generated during the quality driven flaring events would be eliminated.

See Attachment I for example schematic of the equipment installations that would be involved in Case 3 and 4.

Listed below is a summary of the overview of the analysis performed and the results of the analysis.

Storage, Treatment, & Recovery Scenario - Emission Reduction & Cost Effective Analysis									
	Estimated Potential Reductions (tons/yr)					Cost Effective Basis (tons)	Cost of Control ($MM)	Annualized Cost of Abatement System ($MM)	Cost Effectiveness Basis ($/ton)
Case	VOC	SO2	Nox	CO	PM				
1	-0.15	-0.62	-0.02	-0.19	*negligible*	-0.98	$ 3.25	$ 1.06	$ (1,084,092)
2	-1.12	-4.51	-0.13	-1.38	-0.01	-7.16	$ 7.50	$ 2.51	$ (350,420)
3	-1.57	-6.35	-0.19	-1.94	-0.02	-10.07	$ 23.40	$ 6.19	$ (615,476)
4	-2.02	-8.18	-0.24	-2.51	-0.02	-12.97	$ 23.40	$ 6.19	$ (477,509)

[1] Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levilized cash flow method". Costs for equipment were based on cost curves developed by a third-party.

It should be noted that the cost basis did not include the consideration of infrastructure adequacy and did not include all potential equipment and instrumentation necessary. It is expected that once a more rigorous evaluation is performed the costs will significantly be impacted. For example, the cost of infrastructure needs for equipment utilizing electricity and air is expected to be significant. Attachment N contains data utilized to calculate the cost effectiveness of the four cases described above. The storage sphere costs were based on quotes provided by Chicago Bridge and Iron and are contained in the Attachment. A cost curve was prepared by a third-party for the compressor costs. The costs were based on data points of actual costs provided by WSPA membership.

For Case 3 and 4, the evaluation is based on the need for installation of new major systems in order to increase recovery of flare gases from current levels:

- Additional flare gas recovery compressor capacity - the estimated cost to provide additional compressor capacity to recover vent gas flowing in the flare header in excess of current compressor capacity, for transfer to storage and / or treatment. Costs provided are for one unspared compressor system to be added to one existing flare header. The estimate is for a reciprocating compressor with all necessary appurtenances for operation, including knock out pots, coolers, and instrumentation for a fully functional system.

- Addition of surge volume storage capacity – the estimated cost to provide temporary surge storage for a portion of the gases routed to the flare header in excess of the volumes currently being recovered, treated, and consumed. The addition of temporary surge storage volume is necessary for any further increase in flare gas recovery to allow flare gas flow (which is highly variable) to be matched to the demand for fuel gas. The cost used is based on a storage volume equal to the total volume of gas accumulated over one day, and is based on recovery in a high pressure sphere system with discharge at a controlled rate back to the flare gas header. Other lower pressure approaches were considered (low pressure gas holder, medium pressure sphere), but for the sizes analyzed a high pressure sphere was identified as the preferred approach based on operational, safety and economic considerations.
- Additional recovered gas treatment capacity – the cost of additional amine-based treating capacity to process recovered gases for sulfur removal so that they can be burned by existing fuel gas consumers without exceeding environmental or equipment operational limits. The assumption is that for small increases in treating capacity the existing treater(s) will be modified / upgraded to allow for the increase. No additional cost has been included for expansion of sulfur recovery system capacity.

Based on this review the Phillips 66, San Francisco Refinery has concluded that further expansion of systems for the recovery, treatment and use of flared gases is not the most effective approach to reducing these emissions. The refinery has concluded that the major source of flared gases on a volume basis can be attributed to large flow rate, low quality flaring events, especially those of extended duration such as may occur during emergency events or prolonged shutdowns where systems within the refinery are out of fuel gas (and / or hydrogen) balance.

The refinery has allocated significant resources to the development of procedures to plan for, manage, and minimize large flow and duration flaring events. Further resources have also been allocated effectively to ongoing preventive maintenance programs, and even to adjust refinery operations on a severity and throughput basis. These approaches have been identified to be more effective than providing additional flare gas recovery system capacity. Additionally, it is expected that the practices discussed in this plan, specifically the development of a formal turnaround flare management procedure, continuation of incident investigations, and management system programs will result in further reductions of flaring events. These will likely prove to be most cost effective and meaningful.

4.2.2.2 Preventing Production of Low-Quality Flare Gas

Measures to help prevent production of low-quality flare gas, e.g. sour gas, low Btu gas, high nitrogen content are further investigated in this section. The discussion is integrated with the discussion of turnaround and maintenance events as gas quantity (insufficient demand) and gas quality (unscrubbed during upset/malfunction and nitrogen/steam during turnaround) are the primary drivers for flaring during these events. It is for this reason that the measures used to minimize production of low quality fuel gas are closely related to those that can be applied to reduce flaring during maintenance and turnaround events.

Preventing production of sour flare gas is accomplished by making sure that recovered flare gas is routed to the fuel gas system via a gas treating system. It is preventing the production of sour fuel gas that drives the need to match the capacity of treating systems to accept flare gas to flare gas recovery capacity.

High fuel gas nitrogen levels are primarily caused by the nitrogen used to purge hydrocarbons from equipment in preparation for equipment opening. High nitrogen fuel gas content is controlled by limiting the rate at which nitrogen is introduced to equipment and ultimately the flare gas system during nitrogen purging operations. There can be a trade-off between nitrogen flowrate and the effectiveness with which the nitrogen mixes within the contents of the vessel from which hydrocarbons are being removed. These must be balanced on a case-by-case basis to determine the purge rate that represents the best compromise among competing process needs. Scheduling decommissioning activities to minimize overlapping nitrogen purge events is one of the best ways to control the nitrogen content of flare gas.

4.3 Recurrent failure (401.4.3)

- of Pollution Control Equipment
- Process Equipment, or
- A process to operate in a normal or usual manner:
-

4.3.1 Reportable Flaring Events Attributable to the Same Process or Equipment Item

For the Period from June 30, 2012 to June 30, 2020

A discussion and analysis of each event, including actions taken to avoid future flaring as a result of the same cause and the adequacy of maintenance schedules and protocols. Flaring as the result of malfunctions and upsets is included in the analysis. Attachment H contains a listing of the reportable events and the associated corrective actions.

Reportable Flaring Events Attributable to the Same Process or Equipment Item		
Date	**Process or Equipment Item**	**Actions Taken to Avoid Future Flaring**
1/18/12 3/26/12 9/30/14	Air Liquide removal of RFG A from process feed to change feed gas coalescer filter.	Third party Hydrogen Plant installed a tie in for potential future additional water filter. Temporary piping to blow down was added for the bleed at the low point in the RFG A gas line prior to going to Air Liquide. Phillips 66 communicated with Air Liquide regarding the filter replacements. Phillips 66 and Air Liquide discussed having better communication prior to Air Liquide conducting the filter replacements and notifying appropriate refinery personnel so that flaring can be minimized or eliminated. Since the incident on 9/30/14, Air Liquide has replaced the filters without another flaring RCA being triggered.
1/25 – 2/4/15 2/4 – 2/5/15 2/14/15	Equipment inappropriately sized or installed at Unit 246 G-802 Hydrogen Gas Recycle Compressor.	Replace 0.5 amp fuse with 2.0 amp fuse associated with the solenoid valve that maintains oil pressure on the G-802 trip and throttle valve (Gimpel valve). Review all other fuses associated with this control system and panel for proper sizing. Replace improperly sized fuses as necessary. Write a checklist procedure for dry gas seal installation on the U246 G-802 seals. Procedure should call out the appropriate seal drawing and require a craftsperson to mark each step as completed. This checklist will include all major components to install the seals including the socket head screws that were inadvertently omitted prior to the February 4th startup attempt. Conduct refresher training on Maintenance Procedure (MP) 2.53, *Safe Assembly of Tubing Connections Guideline,* with P66 and contractor instrument technicians, pipe fitters and machinists. Audit training records for those performing instrument tubing assembly per MP 2.53 requirements.

4.3.2 Means to Prevent Recurrent Failure

There are many programs in place in order to prevent recurrent failures. The programs fall into two major categories; proactive and reactive. The purpose of the proactive programs is to have systems in place based on potential failures that could occur in order to prevent failures from occurring. The reactive programs examine failures that have occurred in order to learn from the failure and develop stronger proactive programs to prevent recurrence. The facility employs many levels of proactive and reactive programs.

4.3.2.1 Proactive Programs

BAAQMD Regulation references "the adequacy of existing maintenance schedules and protocols" for air pollution control and process equipment in respect to recurrent failures. There are major programs in place which support the prevention of failures. Additionally, these programs facilitate continuous improvement to prevent failures. Key programs in place are described below.

Phillips 66 HSE Management System

Phillips 66 Corporation requires each refinery to implement a standard Health, Safety, and Environmental (HSE) Management System. This is achieved through providing organization structure, programs, procedures, processes, and resources to manage business activities safely and with respect and care for the environment. The HSE Management System seeks to:

- Demonstrate management commitment to health, safety, & environmental stewardship.
- Ensure that all reasonably practicable steps are taken to identify the hazards and risks arising from business activities.
- Establish adequate control over business activities with the aim of achieving safe, incident, and injury free working conditions.
- Maximize the operational integrity, reliability, and efficiency.
- Ensure regulatory compliance.
- Promote high standards and the continuous improvement of HSE performance.

Process Safety Management (PSM)

The refinery must comply with EPA's PSM. Major elements of PSM are also incorporated in California's Accidental Release Prevention Program (CalARP), the Contra Costa County (CCC) Industrial Safety Ordinance (ISO) and EPA's Risk Management Program. There are fourteen elements of PSM, each of these elements is included in some fashion with the programs listed above. In addition, the CCC ISO and CAL ARP program have some additional elements. Although all the elements directly or indirectly prevent failures or minimize the impact of a failure if it occurs, listed below are some of the programs that most directly support failure prevention.

Employee Participation – Employees at all levels must be involved with the elements of PSM. This encourages ownership, participation and buy-in of incident investigation results and means for improvement, and promotes a better safety and operating culture.

Process Safety Information (PSI) **–** the refinery is required to maintain accurate Process Safety Information. PSI includes chemical inventory, accurate drawings, operating procedures, etc.

Process Hazards Analysis (PHA) **-** A PHA is a systematic evaluation of the hazards involved in the process. PHAs are required for initiation of a process and at least once every five years after that. The PHA team should be multi-disciplinary, including maintenance, operations, and engineering. The facilitator of the PHA must be trained in the methodology being used. For proper conduct of a PHA, the PSI must be as complete as possible. One of the values of PHA's is to identify potential hazardous and develop means for mitigating hazardous before they occur.

Operating Procedures **-** Operating procedures include not only the steps for normal operations, but for upset conditions, temporary operations, start-up, and shutdown. Very important safety information must also be included in operating procedures. Contained in the procedures are basic hazards of exceeding operational limits, appropriate response to upset conditions, safety and health information, and emergency operations. The procedures are required to be up to date and reliable. They are also a critical element in training of personnel.

Training **-** Training is required for all employees new to a process before they become involved in that process. The training must include the hazards of the chemicals and process and what is necessary to protect themselves, their fellow employees, and their surrounding communities. Training should be both written/classroom and hands-on. Employers must evaluate the effectiveness of training and make adjustments to content and frequency of training based on those evaluations.

Pre-Startup Safety Review (PSSR) **-** The Pre-Startup Safety Review is done before startup of a new operation or startup following a change in the process (see Management of Change, below). It is a means for ensuring that all essential action items and recommendations from the PHA have been completed prior to beginning operations. It is also the point at which the design parameters and standards used for construction are verified. If training or modifications to Process Safety Information (PSI) are necessary, completion of these items is also verified during the PSSR. Startup should not be allowed to occur until all safety-critical PSSR items have been completed.

Mechanical Integrity **-** Employers are required to have a program to ensure the integrity of processes and equipment. Aspects include listing applicable equipment, training of maintenance personnel, inspection and testing, and maintenance of such systems as controls, vessels, piping, safety systems, and emergency systems. Development and modifications to the mechanical integrity program should be made based on operational experience, relevant codes, and industry standards.

Management of Change (MOC) **-** "Change" includes anything that would require a change in Process Safety Information. This includes changes to equipment, processes, and instrumentation. A proper MOC system requires that any change be evaluated prior to its implementation. The level of evaluation can depend on the degree of change and its criticality to the safety of the operation. In addition to the evaluation and approval of a change, MOC requires that suitable training be conducted (if necessary) and the relevant PSI be updated.

Compliance Audits **-** Per OSHA, compliance audits must be conducted at least once every three years. The purpose of the audits is to determine whether the practices and procedures developed under the provisions of the PSM standard are being followed and are effective. The auditor(s) must be knowledgeable in PSM and should be impartial to the facility being audited. An audit report must be developed and the employer must promptly respond to each of the findings. Once deficiencies are corrected, the corrective action must also be documented.

Maintenance Excellence Philosophy

Predictive Maintenance - The Rodeo Refinery utilizes predictive maintenance tools for both rotating equipment (pumps, blowers, fans, motors) and fixed equipment (pressure vessels, piping, storage tanks). These tools can be used to predict equipment condition and failures so that appropriate preventive measures can be taken, or so repairs can be scheduled prior to a failure. The Rotating Equipment/Reliability Department is responsible for ensuring that rotating equipment is in good condition and the Metallurgical Engineering and Inspection (ME&I) department is responsible for inspecting fixed equipment in the facility.

ROTATING EQUIPMENT

The following is a list of tools and techniques used for maintaining the rotating equipment:

- Operator Inspections/Seal Integrity
- Equipment Deficiencies
- Vibration Analysis
- Lube Oil Testing
- Overhaul Testing

Operator Inspections / Seal Integrity

Operators visually inspect the equipment case and seal/packing area for signs of leakage. Mechanical seals are the number one failure mode in centrifugal pumps. Operations and maintenance personnel include visual monitoring of seals in their shift rounds. In some cases, for example where dual seals are installed, instrumentation (level, pressure, etc.) is available to alert operations that action is required. Seals subject to LDAR (Leak Detection and Repair) regulations are monitored for hydrocarbon emissions on a regular basis.

Operators listen to and observe the equipment operation to detect any unusual noises and/or vibrations that may indicate damage or wear.

Equipment Deficiencies

If a potential deficiency is observed, the operator contacts the Operations Supervisor to request consultation by the appropriate craft or by the Rotating Equipment Group. If it is determined that repair is required, the operator submits a Work Request via the Computerized Maintenance Management System and initiates the steps necessary to make the equipment available for repair. The Work Request documents the deficiencies noted during the operator inspection.

Vibration Analysis

Vibration analysis can be a useful predictive maintenance activity to identify potential equipment failures so that proper maintenance can be scheduled before a failure occurs.

Vibration readings are taken using hand-held piezoelectric accelerometers. Readings are normally taken on all bearing planes (horizontal, vertical, axial). Local panel readings for vibration and temperature, where applicable, are also entered into the data collector. The data is then typically uploaded into the vibration analysis computer, which can be compared to historical data, industry guidelines, or vendor data to assist in scheduling maintenance or indicating the need for additional detailed analysis. Rodeo Refinery personnel participate on a Phillips 66 Rotating Equipment Best Practices Network to facilitate learning in this area.

Lube Oil Testing

Several pieces of rotating equipment are classified as critical. A sample of lube oil is drawn from the appropriate critical equipment, or other machinery of interest, quarterly or as warranted. This sample is sent to a certified laboratory for a standard set of analyses. The results are transmitted to the Machinery Specialist. The results of each analysis are entered into a computer database as a single record. The data included in the record are:

- Equipment tag number
- Date of sample
- Analysis results

Sample test results are trended and compared to established limits of operation for each specific piece of equipment. If a deficiency is noted, the Machinery Specialist initiates an appropriate corrective action. These could include continued monitoring, oil replacement, filtration, or a repair of the equipment.

Overhaul Inspections

Equipment that has been removed to the shop for repair undergoes a detailed internal inspection to identify wear or damage that could affect performance or mechanical integrity. Machinists perform visual inspections and measure clearances for comparison to manufacturer's specifications. If necessary, the Inspection Group can perform more sophisticated tests (radiographs, ultrasonic, magnetic particle, liquid penetrant and materials analysis) if requested by the Rotating Equipment Group or Maintenance.

FIXED EQUIPMENT

The Rodeo Refinery utilizes the following techniques to ensure fixed equipment is in good condition:

- External Visual Inspection,
- Internal Visual Inspections, and
- Thickness Surveys.

External Visual Inspection

The primary reasons for performing external visual inspections of pressure vessels, piping and storage tanks are to determine the type, rate and causes of any deterioration present that may negatively affect their mechanical integrity and/or service performance and to determine if any maintenance work is required to maintain the equipment in a safe operating condition.

External visual inspections are performed by qualified Phillips 66 or contract inspectors. The external visual inspection results are documented in an external inspection report. The report is completed and dated by the inspector(s) performing the external visual inspection. It is reviewed by the plant's Inspection Supervisor or authorized representative. The completed report is filed in the equipment inspection history file located in the plant's Inspection Department.

Internal Visual Inspection

The primary reasons for performing an internal visual inspection are:

1. to determine if the essential sections of the vessel are safe to operate until the next inspection;
2. to determine the type, rate and causes of any deterioration present which may negatively affect its mechanical integrity; and,
3. to determine if any maintenance work is required to maintain the pressure vessel in a safe operating condition.

The internal visual inspections are performed by qualified Phillips 66 or contract inspectors.

Pressure vessels are typically visually inspected internally at least once every 10 years, in accordance with API standards. Non-fired boilers are inspected every 6 years maximum and fired boilers are inspected every 3 years maximum, in accordance with State of California requirements. In practice, many vessels and heaters in sulfur plants are visually inspected internally during a boiler inspection period, at a 3, 6, or 9 year interval and therefore, well within the 10 year maximum interval allowed by API industry standards.

The inspection results are documented in an internal inspection report. The report is completed and dated by the inspector(s) performing the internal visual inspection. It is reviewed by the plant's Phillips 66 Inspection Supervisor or authorized representative. The completed report is filed in the equipment inspection history file located in the plant's Inspection Department.

Thickness Survey

A representative number of thickness measurements are taken on pressure vessels via ultrasonic and/or radiographic thickness techniques for remaining wall thickness at intervals pre-established by the industry. Thickness surveys are also performed on most process piping runs. The thickness survey is prompted by the plant's Inspection Department to meet all requirements for thickness surveys as outlined in the applicable API standard.

The thickness surveys are performed by qualified Phillips 66 or contract inspectors who have the appropriate education, experience and qualifications.

The general area of each thickness monitoring location (TML) is ultrasonically scanned and/or radiographed and the lowest reading is recorded. When using ultrasonics, scanning the general area rather than monitoring the same exact location increases the chance of finding local corrosion and typically yields a larger (more conservative) general corrosion rate.

The thickness survey results are completed and dated by the inspector(s) performing the thickness survey. It is reviewed by the Phillips 66 site Inspection Coordinator or authorized representative. The completed report is filed in the appropriate equipment file and all data is recorded in an electronic database (PCMS System).

Preventive Maintenance - Preventive maintenance activities ensure that equipment and instrumentation function properly through their design life. Examples of these activities are outlined below. Deficiencies are corrected at the time of the inspection where possible or work orders are written to facilitate cleaning or repair.

Instrumentation
Instruments that are critical to unit operations are reviewed and calibrated and cleaned as needed. Examples include flow meters, fire eyes, temperature monitoring devices and analyzers used for performance monitoring and control. Plant performance testing, through pressure surveys, temperature indicators, efficiency calculations or other data collection is used to resolve discrepancies in measurement devices.

Rotating Equipment
To ensure reliable operation of rotating equipment, spare equipment can be operated, where installed, to facilitate repair. Seals and bearings are replaced based on inspections or predictive maintenance activities.

Preventive maintenance tasks include cleaning, adjustment, and lubrication. Operators replace lubricating oil and grease on a frequency set by a master schedule for the Refinery. Appropriate lubricants are specified in a written plan. Steam turbine drivers' over-speed trip protection devices are tested at an established frequency. Fans and mixers are cleaned, lubricated and tested.

Fixed equipment
Thickness measurements and corrosion monitoring (probes, coupons, external UT, and critical process variables) are used to schedule preventive maintenance on vessels. Refurbishment of steel through weld buildup, plate replacement, coatings, or vessel replacement is used to ensure the mechanical integrity of pressure vessels. Refractory is replaced based on inspections, monitoring skin temperatures and thickness in fired equipment and based on internal visual inspections of refractory condition.

Jacketing/Tracing
Integrity of steam and electric tracing used in sulfur processing units is verified through regular plant walkthroughs/checklists by plant operations and maintenance personnel.

Catalyst & Chemicals

Unit catalyst and chemical activity is monitored by unit engineers and operators through pressure surveys and temperature indicators. Lab testing is conducted on intermediate and products to monitor quality. When quality is compromised, operational parameters or other means are employed to ensure continued performance.

<u>Turnaround Inspection And Repair</u> - Major maintenance turnarounds of the process and utility units are planned based on predictive/preventative maintenance activities. Prior to each planned shutdown, a work scope is developed for detailed inspection, repair, replacement and testing of equipment, catalyst and chemicals to ensure the unit will operate properly until the next planned shutdown.

The exact activities for each planned shutdown are determined by Operations, ME&I, Engineering, Reliability and Maintenance personnel prior to each shutdown. A criticality ranking process is used to determine which proposed work activities are included in the turnaround inspections and repairs.

Where practical, maintenance is performed on the equipment while the unit is still in operation. Typical turnaround activities include cleaning equipment, replacing/rejuvenating catalyst and chemicals and inspecting/repairing/replacing equipment as-needed.

<u>Critical Instruments & Safety Instrumented System</u>

The facility has a list of critical devices and has a procedure for handling Safety Instrumented Systems. Safety Instrumented Systems (SIS) take processes to a safe state when predetermined conditions are exceeded. This includes set points such as pressure, temperature, level, etc. These programs maintain the reliability of such devices and systems in order to ensure that shutdown systems have been appropriately established and are reliable.

<u>Near Miss/Good Catch Program</u>

A process is in place that encourages all employees to identify and report potential near misses. Near misses are undesired events which, under different circumstances, could have resulted in harm to people, damage to property or the environment, or production/business loss. Near misses may also include unsafe practices, acts or conditions. The value of this program is that it facilitates:

- Identifying and addressing safety, procedural, environmental impact, design or equipment issues in a proactive, non-threatening manner.
- Identifies learning or training opportunities.
- Sharing of “lessons learned” and best practices with other employees and facilities.

<u>Solomon Refining Comparative Analysis</u>

The refinery participates in periodic comparative analysis. Flare volumes are one of the parameters included. Flare volumes are included in the metric to examine materials that could have been recovered from an economic standpoint. The purpose of the analysis is to determine how facilities compare with their peers in critical parameters.

4.3.2.2 Reactive Programs

When a failure has occurred, depending on the magnitude of a failure, the event will be examined in further detail. Listed below is an overview of the major elements of the programs in place to prevent recurrence of failures.

Incident Investigation

An internal procedure is in place which identifies the type of failures which require incident investigation. This process is a key part of our Health, Safety, and Environmental Management System. Failures captured by this process typically include accidents, injuries, events with potential off-site impact, some levels of flaring events, upsets which result in business loss. The procedure requires that an investigation be conducted and corrective actions identified. The regulatory drivers for this program include, but are not limited to; EPA's PSM, EPA Risk Management Program, Contra Costa County (CCC) Industrial Safety Ordinance (ISO), California's Accidental Release Prevention Program (CalARP). Additionally, there are strong business case drivers for completing incident investigation and preventing recurrence.

Root Cause Reporting

In addition to the incident investigations described above, root cause is required to be reported for higher level events based on various regulatory drivers. Regulatory drivers include but are not limited to; BAAQMD regulations 12-11 & 12-12, EPA SARA/CERCLA reporting requirements, Phillips 66 EPA Consent Decree requirements, Contra Costa County ISO.

Flare Monitoring & Reporting Procedure

The procedure documents the BAAQMD monitoring and reporting requirements. Additionally, it contains levels in which flare incident investigations must be conducted. The levels correspond to those required by BAAQMD and in the Phillips 66 Consent Decree. See Attachment E for general overview of the process for reviewing flaring events.

Use of Incident Investigation Documentation Software

Phillips 66 requires use of a Corporate wide software tool in which certain risk levels of incidents must be tracked. An overview of the incident is included in the software as well as the corrective actions. Depending on the level of the incident, the overview of the incident is immediately shared with Vice President level staff electronically via the software.

High Learning Value Event (HLVE)

If an event occurs in which a lesson learned might have value to sister refineries within Phillips 66 a system has been established for quickly sharing lessons learned so that other facilities may not experience a similar incident.

Corporate Incident Notification Requirements

Higher level events, such as off-site impacts, require immediate notification to the Corporation.

Corporate Health, Safety, and Environmental Reporting Requirements

Flaring volumes are required to be reported and are tracked refinery by refinery to the Corporation on a regular basis.

Key Performance Indicators (KPIs) -

KPIs are reported internally throughout the facility on a periodic basis. The KPIs include the number and cause of flaring events. The purpose is to inform plant personnel of occurrences of these events and to encourage continuous improvement by tracking cause and number.

Regulatory Notifications

There are various regulatory drivers which require notification of various levels of flaring events. Drivers include; BAAQMD 12-12, EPA's SARA/CERCLA, CCC Community Warning System requirements, etc.

5.0 Other Information Requested by APCO to Assure Compliance (401.5)

5.1 New Equipment Installations (404.2)

No other information has been requested by the APCO.

6.0 Root Cause Analysis and Corrective Action Requirements for Flares

6.1 BAAQMD Reportable Flaring Event Determination & Reporting of Cause

The BAAQMD mandates that root cause analysis be performed for flare events which exceed defined parameters.

Flaring Incident Definitions	BAAQMD 12-12-406
• Main Flare • MP30 Flare	≥500 lbs SO_2 per 24-hr ≥ 500,000 scf per calendar day
Root Cause Analysis (RCA) Completion Deadlines	Within 60 days following the end of the month [12-12-406][1] [1] The Phillips 66 Consent Decree requires ≥500 lbs SO_2 cause analysis to be completed within 45 days.

6.2 Root Cause Analysis and Corrective Action Requirements for Flares under MACT CC

The Refinery Sector Rule (RSR) changes under MACT CC, effective January 30, 2019, has new requirements for flares under 40 CFR 670(o)(3) with regard to conducting a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either of the following criteria

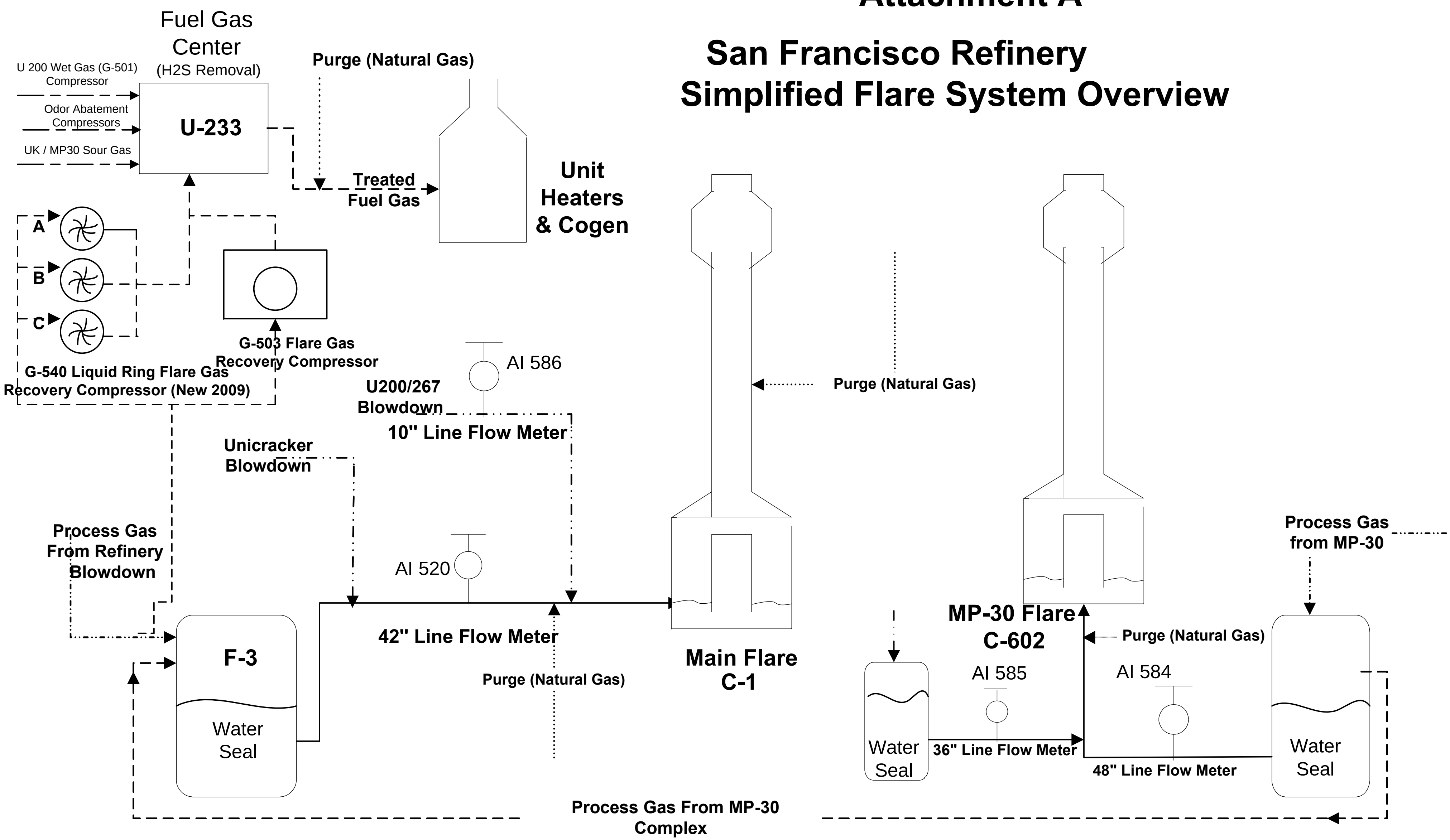
Flaring Incident Definitions	40 CFR 63.670(o)(3)
• Main Flare • MP30 Flare	• **> Smokeless Capacity**: The vent gas flow rate exceeds the smokeless capacity of the flare based on a 15-minute block average, and • **Visible Emissons** : Visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event. or • **>Smokeless Capacity**: The vent gas flow rate exceeds the smokeless capacity of the flare, and • **Velocity >400 fps or >Vmax**: the 15-minute block average flare tip velocity exceeds the maximum flare tip velocity.
Root Cause Analysis (RCA) Completion Deadlines	Within 45 days following the event. [1] The Phillips 66 Consent Decree requires ≥500 lbs SO_2 cause analysis to be completed within 45 days.

ATTACHMENT A

SAN FRANCISCO REFINERY
SIMPLIFIED FLARE SYSTEM OVERVIEW

Attachment A

San Francisco Refinery
Simplified Flare System Overview



ATTACHMENT B

Phillips 66
San Francisco Refinery, Rodeo, CA
Flare Gas System Detailed Description

Listed below is a detailed overview of the facility flare system. Although some parameters are contained in this description they are subject to change as operational or safety enhancements are identified.

The Refinery Relief and Blowdown Systems provide a means for recovery or safe disposal of gases and liquids, which may be generated by the process units. Typical sources of normal flow include coke drum steamout and switching, sampling, activation of relief valves, distillation tower overhead vapors, and purging of equipment for maintenance or startup. During emergencies, major flow may occur from heater or unit depressuring and the lifting of pressure relief valves. Gases and liquids flow through relief and blowdown lines to blowdown accumulators and knockout drums. Gases and vapors pass overhead to be recovered or flared. The liquids are generally reprocessed through appropriate operating units.

There are two flares in the refinery – the Main Flare and MP-30 Flare. There are three relief and blowdown systems; the Refinery, the Hot Coker Blowdown, and the MP-30 system. Typically the gases sent to the blowdown systems are recovered, treated, and then utilized for fuel in the facility heaters and co-generation equipment. During periods when gases are not recovered, the flare gases are typically sent to the Main Flare. The Refinery and Hot Coker Blowdown system gases are routed to the Main Flare. The units located in the MP30 Complex relieve to the MP-30 Blowdown system. Typically, the gases sent to the MP-30 Blowdown System are recovered in conjunction with the gases from the Refinery and Hot Coker Blowdown system due to interconnecting piping. This interconnecting piping also accommodates minor flaring so that gases from the MP-30 Blowdown System are typically sent to the Main Flare. During major releases from MP-30, the gases would be flared at the MP-30 flare.

There are periods in which the Main Flare is shutdown in association with the Unicracker Complex shutdown. During these periods, the Refinery Blowdown system can be diverted to the MP-30 Flare. The Hot Coker Blowdown system would also be diverted to the MP-30 Flare while the Main Flare is shutdown.

<u>Refinery Relief and Blowdown System</u>

The Main Relief and Blowdown system handles relief and blowdown from the Coking Unit 200, Crude Unit 267, Gasoline Fractionation, Caustic Treating and Deisobutanizer Unit 215, Diesel Hydrotreating Unit 250, Steam Power Plant, Hydrogen Plant Unit 110, Fuel Gas Center Unit 233, the Unicracker Complex including Reforming Unit 244, Unit 246 Heavy Oil Hydrocracker (mid-2009), and Unisar Unit 248, Sulfur Units, Isomerization Unit 228, the Unit 120 3rd Party Hydrogen Plant (mid-2009), and minor MP-30 releases.

<u>F-1 Blowdown Drum</u>

Vapor and liquid releases from the units listed above flow through various blowdown headers to Refinery Blowdown Drum F-1. The Unicracker complex has its own separate Blowdown Drum F-45 upstream of F-1 to limit the liquid releases to F-1. Vapor and liquid release from the Unicracker Complex discharge into F-45. Liquids are knocked out and the vapor flows from F-45 through a 36-42″ header to F-1. Not all relief valves from the Unicracker Complex discharge to F-45. Relief valves from D-305 Fractionator discharge directly into the 36-42 ″ header from F-45.

The Steam Power Plant and Unit 110 also have separate Blowdown Drums upstream of F-1 – Blowdown Drum F-35 and Flare Knock Out Drum V-18, respectively. The sites of the Steam Power Plant and Unit 110 have low points in their relief headers. Liquids condensing in the SPP and Unit 110 flare headers to F-1 flow back down the flare header to their respective blowdown drums.

Entrained liquids are knocked out in F-1. At a high liquid level in F-1, blowdown pumps G-1A/1B automatically start and pump the collected liquid through Cooling Water Exchanger E-1 to the foul water tank. The foul water tank has a water phase and hydrocarbon liquid phase. The water phase is fed to the Phenolic Water

Stripper D-901. The hydrocarbon liquid phase becomes feed to Coking Unit 200 or to Naphtha Hydrotreater Unit 230.

F-3 Water Seal Drum and G-503 Flare Vapor Recovery Compressor

Water Seal Drum F-3, located between drum F-1 and the Main Flare, permits the use of the blowdown system and its drums as suction surge for the G-503 Flare Vapor Recovery Compressor during normal releases. F-3 usually contains about an eight foot water seal that diverts the gas in Blowdown Drum F-1 down the main 36″ Unicracker blowdown header to the F-509 Knock Out Drum for G-503. The G-503 compressor, located in the Coker Light Ends area, returns the compressed gases to the refinery fuel gas system. The compressor design flowrate is 200,000 scf/hr of 23 MW gas. G-503 may also spare the Unit 200 G-501 Coker Wet Gas Compressor or the Unit 200 Odor Abatement compressors G-60A/B/C. When the vapor flowrate is higher than 200,000 scf/hr, vapors released to the refinery blowdown system break through the F-3 water seal and flow to the Main Flare. If the vapors released are from the MP-30 blowdown system, the vapors may also break through the F-604 water seal and flow to the MP-30 Flare. When G-503 is in G-501 or G-60A/B/C service, or G-503 is down, the F-3 water seal is removed, and vapors flow directly to the Main Flare. The F-604 water seal is not removed when G-503 is down, so that flaring of the normal releases only occurs at one flare stack.

Main Flare Header

Flare gas from D-7 Blowdown Drum and Unit 240 reactor depressuring gas release downstream of Water Seal Drum F-3. The Unit 240 reactor depressuring line bypasses drum F-1 and Water Seal Drum F-3 to accommodate depressuring of the reactors at a 300 psi/min rate. The Hot Coker Blowdown bypasses the F-3 Water Seal Drum to minimize back pressure on the Hot Coker Blowdown Drum D-7.

Any gas breaking through the F-3 water seal, vapor from D-7, and/or Unit 240 depressuring gas enter the Main Flare Stack C-1 through a water seal at the base of the flare. This seal is one of the flashback protections for the Main Flare - prevents the backflow of gas or air into the flare lines, which could create explosive mixtures. Additional flashback protections are the molecular seal and continuous purge of the flare stack. An on-line oxygen analyzer is located between F-3 and 19C-1 and sounds an alarm on high oxygen content in the Unit 200 DCS to warn operators of potentially explosive mixtures in the flare header

.Vacuum Protection for Refinery Blowdown System

After a hot vapor release through F-3, the water seal in F-3 will be automatically re-established on level control. To ensure flashback from the flare cannot occur, natural gas is added to F-1 on pressure control (PIC-530) at low pressures. The pressure indicator controller PIC-530 indicates and alarms in the Unit 200 DCS.

Main Flare Purge Gas Requirements

Natural gas supplies purge gas to prevent flashback. The purge gas enters the Main Flare above the water seal at the base of the flare. The molecular seal prevents both convective and diffusional backflow of air into the stack. The proprietary seal design allows some of the rising flare and purge gases to be trapped in the seal. This creates a zone, which is higher than atmospheric pressure and lower in molecular weight than air (lighter than air). Air cannot backflow through such a zone.

Smokeless Flaring at Main Flare

A small continuous flow of steam to the flare is provided to prevent a condensate build-up in the steam line and provide cooling to the flare tip. During a flaring event, additional steam is injected at the tip to aspirate air into the flame and ensure smokeless burning of the flare gases. Flow indicators, located on the two flare headers - 10″ header from D-1 and 42″ header from F-1-to the Main Flare stack- detect releases to the flare. These flow indicators also alarm in the Unit 200 DCS, so that the Unit 200 operators are aware that gas is being released to the flare. A monitor of the flare is located in the Unit 200 control room; so that the Unit 200 operators can continuously view the flare operation. If the flare is smoking, the steam flowrate to the flare tip is adjusted manually by the Unit boardman from the Unit 200 DCS. The CFEP project relief system changes are making enhancements to the steam associated with both flares to allow for higher volume flaring events to occur without resulting in a smoking flare. These enhancements will be taking place mid-2009.

MP-30 Relief and Blowdown System

When the Main Flare is in service, normally only the MP-30 Complex major releases flow to the MP-30 Flare. However, the MP-30 Relief and Blowdown System can also handle releases from Coking Unit 200, Crude Unit 267, Gasoline Fractionation, Caustic Treating and Deisobutanizer Unit 215, Diesel Hydrotreating Unit 250, Steam Power Plant, Hydrogen Plant Unit 110, Fuel Gas Center Unit 233, Sulfur Units, and Isomerization Unit 228, when the Main Flare is down for maintenance. During this maintenance period, the blowdown headers for Units 267, 200, 215, 250, 110, 233, 228, Steam Power Plant, and Sulfur Plant Complex headers can be diverted to Blowdown Drum F-2. Releases to F-2 will flow directly to the MP-30 Flare Stack

Diverting the blowdown headers to F-2 is only done, when Blowdown Drum F-1 and/or Water Seal Drum F-3 must also be inspected or repaired with the Main Flare. If F-1 and F-3 do not have to be inspected when Main Flare is down, a 26″ interconnecting line downstream of F-3 is opened to the 36″ header from F-2. This allows the refinery to keep G-503 Flare Compressor in service during the maintenance of the Main Flare and minimize flaring. Only major releases will break the F-3 water seal and flow through the 26″ interconnecting line to the MP-30 Flare.

MP-30 Complex Blowdown Drum F-600

Releases from the Hydrotreating Units 229 and 230 and Reforming Unit 231 flow to Blowdown Drum F-600. Any liquid releases or entrained liquid will drop out in F-600. Liquid in F-600 gravitates to F-603 Drain Pot. On high level in F-603, blowdown pumps G-600/601 automatically start. The liquids are pumped by level control through Blowdown Slops Cooler E-600 to the foul water tank, the same foul water tank for the Refinery Relief and Blowdown System. When level in F-603 has dropped to the preset level, the pumps automatically stop.

Minor vapor releases up to 200,000 scf/hr are diverted from F-600 to the Refinery Blowdown System by a fifteen foot water seal in F-604 Water Seal Drum downstream of F-600. These minor releases flow to the Refinery Blowdown System through a 12″ cross-connecting line to the Sulfur Plant/Isomerization Unit common blowdown header. Major vapor releases break the water seal in F-604 and flow through a 42″/48″ flare header to the MP-30 Flare.

Vacuum Protection for F-600 and F-604

To prevent a vacuum, PIC-601 on F-600 adds natural gas to the MP-30 Blowdown on low pressure. In addition, the pipe entering the F-604 seal leg rises 19 feet above the top of the 15 foot water seal. Therefore, if a vacuum or partial vacuum occurs in the MP-30 blowdown system, water in F-604 will back flow up the seal pipe, but the seal will not be broken.

On low pressure in the flare header, separate pressure controller PIC-658 adds natural gas to the flare line to prevent flashback. A small continuous flow of natural gas through a restriction orifice sweeps the flare line to ensure the line does not contain any H_2S, NH_3, or other heavier hydrocarbons after flaring ceases.

MP-30 Flare F-2 Blowdown Drum (Partial spare for F-1)

When blowdown headers are lined up to F-2, any entrained liquids in the vapor releases or any liquid releases to F-2 are knocked out in F-2. F-2 is also a low point in the system. Any liquid that condenses in the 36″ header will flow back to F-2. At a high level in F-2, blowdown pumps G-2A/B automatically start and pump the collected liquid through Cooling Water Exchanger E-2 to the foul water tank. The foul water tank is the same foul water tank as listed for the Refinery Relief and Blowdown System. When a low level in F-2 is again reached, the blowdown pumps automatically stop.

Even when no Unit blowdown headers are lined up to F-2, F-2 must remain in service when the MP-30 Flare is in service. Any high level at the base of the MP-30 flare is gravity drained to F-2. The continuous purge required for the MP-30 Flare Stack to prevent flashback also flows through F-2.

MP-30 Flare Operation

The MP-30 flare operates similarly to the Main Flare. The MP-30 Flare also has four electronic spark ignited pilots. Pilot operation is basically the same as the Main Flare.

The MP-30 Flare also has a molecular seal. The flare tip is 48″diameter... Natural gas is also used as the purge gas for to prevent flashback. The continuous purge gas requirement of 0.01 ft/sec to the MP-30 Flare Stack is supplied through pressure regulator PCV-565 and flow restriction orifice FO-523 to 19F-2. The purge gas flows from 19F-2 through the 36″ flare header to the MP-30 Flare. (The minimum purge requirement of 445 SCF/hr for this flare stack is set by the manufacturer's molecular seal and flare tip design.)

In addition to the molecular seal and continuous purge, a water seal exists at the base of the flare stack to prevent flashback. The seal is designed to have a continuous water purge of 0.5 gpm. A continuous water purge ensures that any condensed hydrocarbon vapor that may accumulate is removed from the base of the flare. The continuous water purge and/or any condensed hydrocarbon gravitate from to F-2 for removal to the foul water tank.

An on-line oxygen analyzer is located on the main 48″ flare header downstream of the 36″ F-2 flare header and 12″ D-7 header connections. The analyzer sounds an alarm on high oxygen content in the Unit 200 DCS to warn operators of potentially explosive mixtures in the MP-30 flare system.

<u>Smokeless Flaring at MP-30 Flare</u>

A small continuous flow of steam is provided to the flare tip to prevent a condensate build-up in the steam line and provide cooling to the flare tip. When flaring occurs, additional steam is injected at the tip to aspirate air into the flame and ensure smokeless burning of the flare gases. Flow indicators, located on the 48″ header from MP-30, the 36″ header from F-2, and the 12″ header from D-7 detect releases to the flare. These flow indicators alarm on high flowrates in the Unit 200 DCS. A monitor of the flare is also located in the Unit 200 control room; so that the Unit 200 boardman can continuously view the MP-30 flare. If there is a flow to the flare or the flare is smoking, the steam to the flare tip is manually increased by the boardman from the Unit 200 DCS.

<u>Hot Coker Blowdown System</u>

The Hot Coker Blowdown system was built with the Unicracker Complex in 1970. Releases to the hot Coker Blowdown System flow through a 16″ blowdown header to Blowdown Accumulator F-6. Even though the system is described as the Hot Coker Blowdown system, not all releases are hot nor are all releases from Unit 200 Coking Section. Originally, most of the releases to the blowdown system were from relief valves on heater outlets, blowdown lines from heater outlets, and the relief valves on the Unit 200 Coke Drums (hot releases in excess of 650 °F). However, other factors such as type of material released from a relief valve (i.e. crude) will also cause the relief valve to be connected to the Hot Coker Blowdown System. Other Unit 200 connections include Unit 200 Vacuum Tower relief valve, crude feed pump relief valve, various thermal relief valves for heat exchangers, and pump clean-out/ blowdown lines at Unit 200. The Unit 267 Desalter, crude pump relief valves, and Diesel Filter relief valves discharge to the Hot Coker Blowdown System as well. Although Unit 233 can relieve to either F-6 or F-3 the primary route is through F-6. This is manually controlled. During periods of fuel gas imbalance the excess clean fuel gas is vented to F-6 through the 10" line.

Liquid releases to the Hot Coker Blowdown system drop out in F-6. A high liquid alarm on F-6 that sounds on the DCS alerts the Unit 200 Operators that liquid is flowing to F-6. Operators manually start blowdown drum pump G-61 to pump the liquid to the recoverable oil tank. If the liquid is a hot release, the Operators will divert cooler gas oil from Unit 200 to the Hot Coker Blowdown header to cool the liquid release before pumping to tankage.

Any vapor that is released from F-6 flows to Blowdown Drum D-7. On high temperature in the D-7 overhead line (150 °F), a water deluge control valve automatically opens to flood water into D-7. A high temperature alarm sounds in the Unit 200 control room on the DCS and a valve positioner alarm from this control valve sounds on the Unit 200 alarm panel when the deluge valve opens. This alerts operators that a hot release has occurred and additional operator intervention may be required for D-7. Water gravitates through the water deluge control valve from Tank 286 to D-7 and condenses most of the vapor released to D-7 by contact with the vapor by flowing over the disc and donut baffles inside D-7. Any vapor not condensed will flow overhead from D-7 to one of the flares for combustion. D-7 overhead is normally lined up to the Main Flare.

The water and any entrained hydrocarbon liquid will discharge from D-7 through a water seal leg to the process sewer. During any release at the flares or to the Hot Coker Blowdown System, the pressure in D-7 will not exceed 15 psig. This water seal leg ensures that the water seal is not blown during any potential release.

Some of the condensed hydrocarbon in D-7 will separate from the water at the base of D-7. The operators manually line up D-7 bottom to the Blowdown Drum Pump G-61 to pump the hydrocarbon liquids from D-7 to the recoverable oil tank.

Gasses from the Hot Coker Blowdown system are recovered if the pressure in the blowdown does not exceed the pressure necessary to blow the water seal in the C-1 Flare Stack Water Seal Drum. Gasses are periodically sent to the flare from the Hot Coker Blowdown system. This 10" line is monitored with a separate ultrasonic meter. In 2006 there was approximately 150 hours in which flow was sent to the flare from this system. The majority of these 150 hours, approximately 90%, was during a period of fuel gas imbalance when clean fuel gas was being sent to the flare. (Clean fuel gas is not generated from the Hot Coker Blowdown system, excess gas is routed through the 10” line upstream of where the flow is monitored).

Flare Pilots

Each stack tip has four electronic spark ignited pilots, each with its own ignition system. The pilots utilize electronic spark ignition for an automatic re-light function. When the thermocouple on the pilot senses a pilot outage (low thermocouple reading), the spark igniter immediately reacts to re-light the pilot. After a set period of time, the loss of pilot indication will alarm in the DCS in the control room.

As a back-up system to this automatic electronic spark ignition system, each pilot has a manual flame front generator line.

Temperature indicators for each pilot also alarm on low temperature in the to alert the operators that pilot flame-out has possibly occurred. If the low temperature alarm remains on because the automatic spark ignition system has not been successful to re-ignite the pilot, an operator is then dispatched to the field to manually operate the flame front generator to re-ignite the pilot.

Capacity of the Relief and Blowdown Systems

The Refinery and MP-30 flare systems are sized to handle releases during refinery-wide utility failures - refinery-wide power failure, total saltwater cooling system failure, or 150 psig steam failure. The maximum design relief case for both these flare systems is currently a refinery-wide power failure. The relief scenarios were re-evaluated as part of the 2009 CFEP. The design of an individual unit blowdown header may be based on other failures. For example the DIB blowdown header design is based on a refinery-wide salt water failure. The Unit 267 blowdown header design is based on a 150 psig steam failure.

The MP-30 blowdown system (consisting of F-600, F-604, and MP-30 blowdown header) is sized to handle releases from common utility failures for the MP-30 Complex - Units 229, 230, and 231. The two major utility failures, causing the highest relief loads, are power failure and cooling water failure. Power failure creates the highest radiation release concern in the flare area, because a refinery-wide power failure can cause both the MP-30 Flare and the Main Flare to have large releases. An MP-30 cooling water failure creates the highest back pressure in the system for certain MP-30 relief valves.

Interrelated Systems

Wet Gas Stream, process units, and compressor - The light ends section of Unit 200, Crude/Coking Unit, processes the bubble tower wet gas and bubble tower raw naphtha stream to produce a stabilized naphtha. Wet gas (high C3 – C5 content) from the bubble tower reflux drum is compressed by the G-501 Wet Gas Compressor, a multi-stage centrifugal compressor. The compressed gas is mixed with the bubble tower raw naphtha. In exchanger E-511, salt water cools the combined stream before the stream discharges into the F-502 High-Pressure Separator. Vapor from the high-pressure separator flows to the D-503 Absorber. In D-503, the vapor is contacted with a stripped lean oil which removes the heavier components from the vapor. The scrubbed off-gas from D-503 is then pressure controlled to the light ends sour fuel gas header. The combined sour fuel gas stream from the light ends section flows to Unit 233, the Refinery Fuel Gas Center.

The Flare Gas Recovery Compressor (G-503) can be put into Wet Gas Compressor (G-501) service, if needed. This is done on a planned and emergency basis. The value of this is to minimize overall flaring. The “Wet Gas” Compressor runs at a rate much higher than the Flare Gas Recovery Compressor. The Flare Gas Recovery Compressor typically runs at about 50% of the maximum flow on an annual average basis. When the Flare Gas Recovery Compressor is put into Wet Gas Compressor service the entire capacity of the Flare Gas Recovery Compressor is utilized. Although flaring will likely occur, the total rate of flaring has been minimized by approximately 2.3 MMSCFD by placing the Flare Gas Recovery Compressor into Wet Gas Compressor service.

Odor Abatement: stream, process units, and compressor – There is a group of compressors and a closed vent system referred to as the “Odor Abatement” (OA) system. The OA System is a Refinery wide collection system that includes tank blanketing, vacuum towers non-condensable vapor, de-gassing vapors from various processes, butane tanks vents, and the iso-pentane tank vents. Seasonal ambient temperature increases will impact various processes causing an increase in flow of material to the OA System. The purpose of the system is to collect and control vapors from the sources listed above. Natural gas is purged into the system based on certain set points. Natural Gas as Blanketing Gas for tanks has been used due to low H2S/Sulfur content, nil oxygen content, consistent quality, and low molecular weight. Low molecular weight and low H_2S/Sulfur are only critical to finished low sulfur products. Nil oxygen content is critical for finished product and intermediate products to prevent formation of materials that foul preheat exchangers.

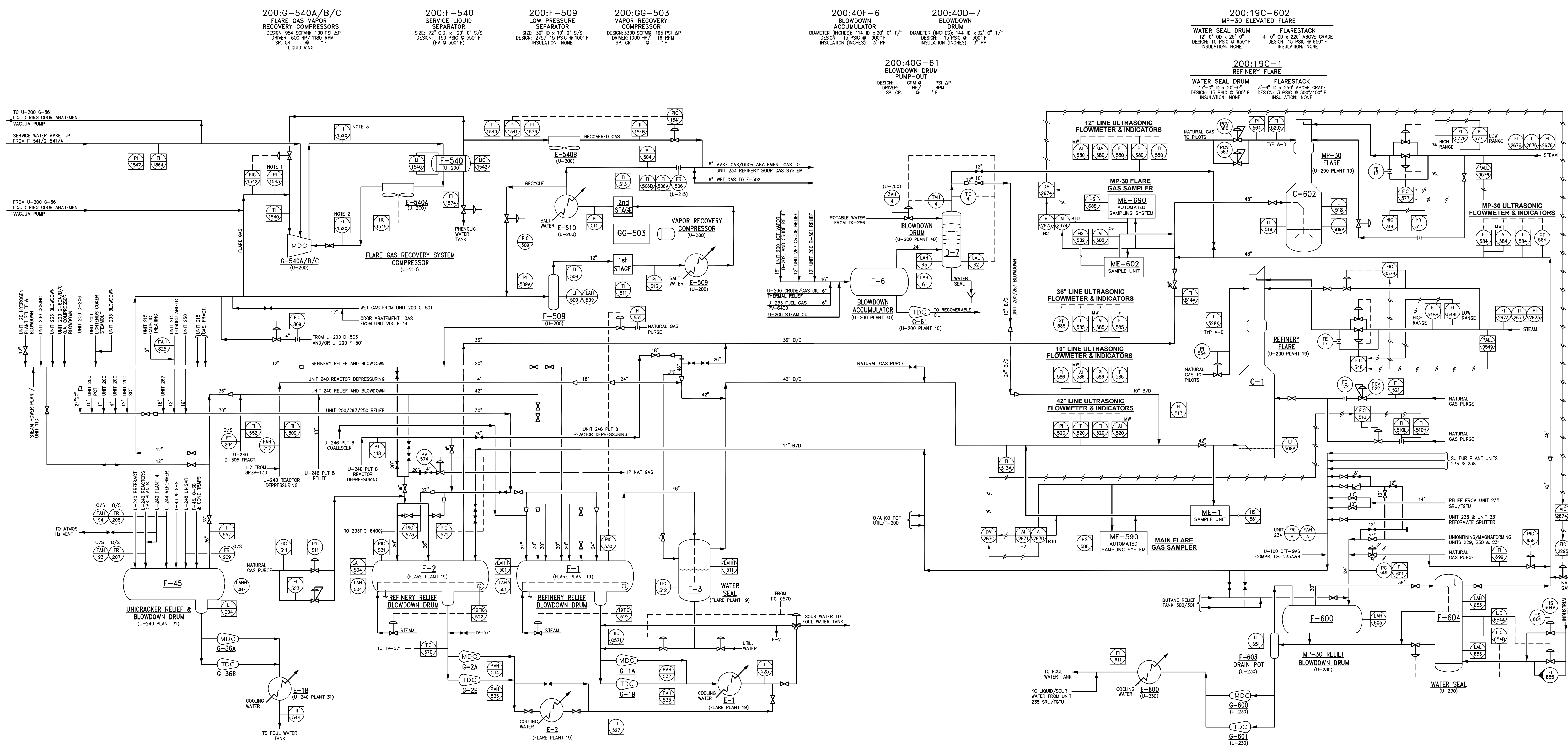
The compressors help maintain pressure in the system and maintain movement of the vapors. The vapors are routed, via the odor abatement compressors directly to Unit 233 Fuel Gas Center. The vapors are co-mingled with other recovered streams, such as the U200 Wet Gas & Flare Gas Recovery vapors, for sulfur removal.

There are 4 odor abatement compressors. Typically, one or two compressors are operating with a third one as backup. A 4th compressor was installed 2nd Quarter 2009. Following the installation of the 4th compressor, 2 to 3 compressors will typically be operated with 1 to 2 spare compressors. The Flare Gas Recovery Compressor can be put into Odor Abatement service, if needed. Without compressor(s) in odor abatement service the tanks and other equipment associated with the system may relieve to the atmosphere, resulting in potential excess emissions and odors. By utilizing the Flare Gas Recovery Compressor in Odor Abatement service, emissions directly to the atmosphere are mitigated but flaring will likely take place.

<u>F-502</u>**-** F-502 which is shown on the PFD shown in Attachment B is related to the Wet Gas Compressor system described above. Gasses collected and compressed in the G-501 Wet Gas Compressor are then sent to the Unit 200 F-502 High Pressure Separator. If the Flare Gas Recovery Compressor (G-503) is utilized in Wet Gas Compressor service then the Flare Gas Recovery Compressor would discharge to the F-502 separator.

ATTACHMENT C

SAN FRANCISCO REFINERY
FLARE SYSTEM PROCESS FLOW DIAGRAM



240:31F-45
RELIEF & BLOWDOWN DRUM
DIAMETER (INCHES): 132 ID x 30'-0" S/S
DESIGN: 50 PSIG @ 650° F /20 PSIG @ -50° F
INSULATION (INCHES): NONE

240:31E-18
PUMP-OUT COOLER
22.6 MM BTU/HR (DESIGN)
DESIGN: (SHELL) 160 PSIG @ 500° F
DESIGN: (TUBE) 150 PSIG @ 250° F
INSULATION (INCHES): NONE

200:19F-2
REFINERY RELIEF BLOWDOWN DRUM
DIAMETER (INCHES): 11' ID x 30'-0" T/T
DESIGN: 25 PSIG @ 650° F /10 PSIG @ -50° F
INSULATION (INCHES): NONE

200:19E-2
PUMPOUT COOLER (OUT OF SERVICE)
6.7 MM BTU/HR (DESIGN)
DESIGN: (SHELL) 150 PSIG @ 250° F
DESIGN: (TUBE) 200 PSIG @ 350° F
INSULATION (INCHES): NONE

200:19F-1
REFINERY RELIEF & BLOWDOWN DRUM
DIAMETER (INCHES): 15.5' ID x 40'-0" T/T
DESIGN: 25 PSIG @ 650° F /-15 PSIG @ 500° F/10 PSIG @ -50° F
INSULATION (INCHES): NONE

200:19F-3
WATER SEAL DRUM
DIAMETER (INCHES)10'-0" ID x 24'-0" T/T
DESIGN: 30 PSIG @ 500° F
INSULATION (INCHES): NONE

240:31G-36A
PUMP-OUT
DESIGN: 400 GPM @ 78 PSI ΔP
DRIVER: 60 HP/3600 RPM
SP. GR. 0.58 @ 50 ° F HC
&/OR H_2O 1.0 @ 650° F

200:19G-2A
PUMP-OUT
DESIGN: 200 GPM @ 107 PSI ΔP
DRIVER: 60 HP/ RPM
SP. GR. 0.61 @ 450° F

200:19G-1A
PUMP-OUT
DESIGN: 200 GPM @ 107 PSI ΔP
DRIVER: 60 HP/Y RPM
SP.GR. 0.61 @ 450° F

200:19E-1
PUMPOUT COOLER
6.7 MM BTU/HR (DESIGN)
DESIGN: (SHELL) 159 PSIG @ 250° F
DESIGN: (TUBE) 204 PSIG @ 350° F
INSULATION (INCHES): NONE

240:31G-36B
PUMP-OUT (SPARE)
DESIGN: 400 GPM @ 78 PSI ΔP
DRIVER: 60 HP/3600 RPM
SP. GR. 0.58 @ 50 ° F HC
&/OR H_2O 1.0 @ 650° F

200:19G-2B
PUMP-OUT
DESIGN: 200 GPM @ 107 PSI ΔP
DRIVER: 50 HP/ RPM
SP. GR. 0.61 @ 450° F

200:19G-1B
PUMP-OUT
DESIGN: 200 GPM @ 107 PSI ΔP
DRIVER: 50 HP/Y RPM
SP.GR. 0.61 @ 450° F

230:E-600
BLOWDOWN SLOPS COOLER
MM BTU/HR (DESIGN)
DESIGN: (SHELL) 150 PSIG @ 500° F
DESIGN: (TUBE) 150 PSIG @ 500° F
INSULATION (INCHES): NONE

230:F-603
DRAIN POT
DIAMETER (INCHES): 60 OD x 8'-0" S/S
DESIGN: 150 PSIG @ 500° F
INSULATION (INCHES): NONE

230:F-600
KNOCKOUT DRUM
DIAMETER (INCHES): 120 ID x 29'-5" S/S
DESIGN: 28 PSIG @ 500° F
INSULATION (INCHES): NONE

230:F-604
WATER SEAL DRUM
DIA. (IN.): 144 OD x 32'-6" S/S
DESIGN: 50 PSIG @ 650° F
FULL VAC. @ 500° F
INSULATION (IN.): NONE

230:G-600
BLOWDOWN SLOPS PUMP
DESIGN: 150 ACFM @ PSI ΔP
DRIVER: 25 HP/1770 RPM
CASE 1. SP. GR. 1.0 @ 60° F
CASE 2. SP. GR. 0.63 @ 250° F

230:G-601
BLOWDOWN SLOPS PUMP (SPARE)
DESIGN: 150 ACFM @ PSI ΔP
DRIVER: 25 HP/1770 RPM
CASE 1. SP. GR. 1.0 @ 60° F
CASE 2. SP. GR. 0.63 @ 250° F

NOTES:

1. NORMAL OPERATION
   GG-503 & G-561 PLUS ONE ONLY G-540 IS IN SERVICE
   ALTERNATE OPERATION
   G-540A,B & C IS IN SERVICE
   GG-503 & G-561 OUT OF SERVICE

REFERENCE FILE (XREF) FOR THIS DRAWING IS
FLRE-YF-001-001 & FLRE-YF-001-002

REV	DATE	DESCRIPTION	SFE NO.	BY / CHKD	APPD / DATE
9	9-30-20	AS BUILT, M20156769, M20204871 & SFE 16043	16043	LMB / LMB	ASM / 9-30-20
8	12-17-19	AS BUILT, PROJECTS MODIFIED PER SFE 13109 & SFE	17068	LMB / LMB	ASM / 12-17-19
7	7-19-19	AS BUILT, MODIFIED INSTRUMENTATION PER SFE	17068	MM / LMB	ASM / 7-19-19

SIMPLIFIED PROCESS FLOW DIAGRAM
REFINERY FLARE & BLOWDOWN SYSTEM
RELIEF, BLOWDOWN
VAPOR RECOVERY, & FLARE

PHILLIPS 66 COMPANY
San Francisco Refinery

DRAWING NUMBER: RVR-ENVRNM-YF-FLRE-001 | REV: 9

ACAD NO. RVR-ENVRNM-YF-FLRE-001

FILE: RVR-ENVRNM-YF-FLRE-001.dwg
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ATTACHMENT D

Cross Reference Index
40 CFR 63 Subpart CC

40 CFR 63 Subpart CC RSR Flare Plan 63.670(o) Cross Reference Table		
Citation	**Regulation Description**	**All Flares**
63.670(o)(1)(i)	A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.	Att A, B, C, E, M
63.670(o)(1)(ii)	An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized or prevented during periods of startup, shutdown, or emergency releases. The flare minimization assessment must (at a minimum) consider the items in paragraphs (o)(1)(ii)(A) through (C) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.	3.2 Fuel Gas Combustion SO2 Emissions 4.0 4.2.2.1 Att N
63.670(o)(1)(ii)(A)	Modification in startup and shutdown procedures to reduce the quantity of process gas discharge to the flare.	3.1 4.0 4.1
63.670(o)(1)(ii)(B)	Implementation of prevention measures listed for pressure relief devices in §63.648(j)(3)(ii)(A) through (E) for each pressure relief device that can discharge to the flare.	2.2.4
63.670(o)(1)(ii)(C)	Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.	2.2.3.3, 2.2.3.4 3.1 3.2 Fuel Gas Combustion SO2 Emissions 4.2.2.1 Att L Att N
63.670(o)(1)(iii)	A description of each affected flare containing the information in paragraphs (o)(1)(iii)(A) through (G) of this section.	See below
63.670(o)(1)(iii)(A)	A general description of the flare, including whether it is a ground flare or elevated (including height), the type of assist system (e.g., air, steam, pressure, non-assisted), whether the flare is used on a routine basis or if it is only used during periods of startup, shutdown or emergency release, and whether the flare is equipped with a flare gas recovery system.	Att K
63.670(o)(1)(iii)(B)	The smokeless capacity of the flare based on a 15-minute block average and design conditions.	Att K
63.670(o)(1)(iii)(C)	The maximum vent gas flow rate (hydraulic load capacity).	Att K
63.670(o)(1)(iii)(D)	The maximum supplemental gas flow rate.	Att K
63.670(o)(1)(iii)(E)	For flares that receive assist steam, the minimum total steam rate and the maximum total steam rate.	Att K
63.670(o)(1)(iii)(F)	For flares that receive assist air, an indication of whether the fan/blower is single speed, multi-fixed speed (e.g., high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated assist air flow rate at each fixed speed. For variable speeds, provide the design fan curve (e.g., air flow rate as a function of power input).	n/a
63.670(o)(1)(iii)(G)	Simple process flow diagram showing the locations of the flare following components of the flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.	Att B Att C Att K
63.670(o)(1)(iv)	Description and simple process flow diagram showing all gas lines (including flare waste gas, purge or sweep gas (as applicable), supplemental gas) that are associated with the flare. For purge, sweep, supplemental gas, identify the type of gas used. Designate which lines are exempt from composition or net heating value monitoring and why (e.g., natural gas, gas streams that have been demonstrated to have consistent composition, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the flare.	Att C Att J
63.670(o)(1)(v)	For each flow rate, gas composition, net heating value or hydrogen concentration monitor identified in paragraph (o)(1)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.	2.2.4
63.670(o)(1)(vi)	For each pressure relief device vented to the flare identified in paragraph (o)(1)(iv) of this section,	2.2.5

40 CFR 63 Subpart CC RSR Flare Plan 63.670(o) Cross Reference Table		
Citation	**Regulation Description**	**All Flares**
	provide a detailed description of each pressure release device, including type of relief device (rupture disc, valve type) diameter of the relief device opening, set pressure of the relief device and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator.	Att J
63.670(o)(1)(vii)	Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.	3.1 4.0 4.1

ATTACHMENT E

Phillips 66
San Francisco Refinery, Rodeo, CA
Unit List

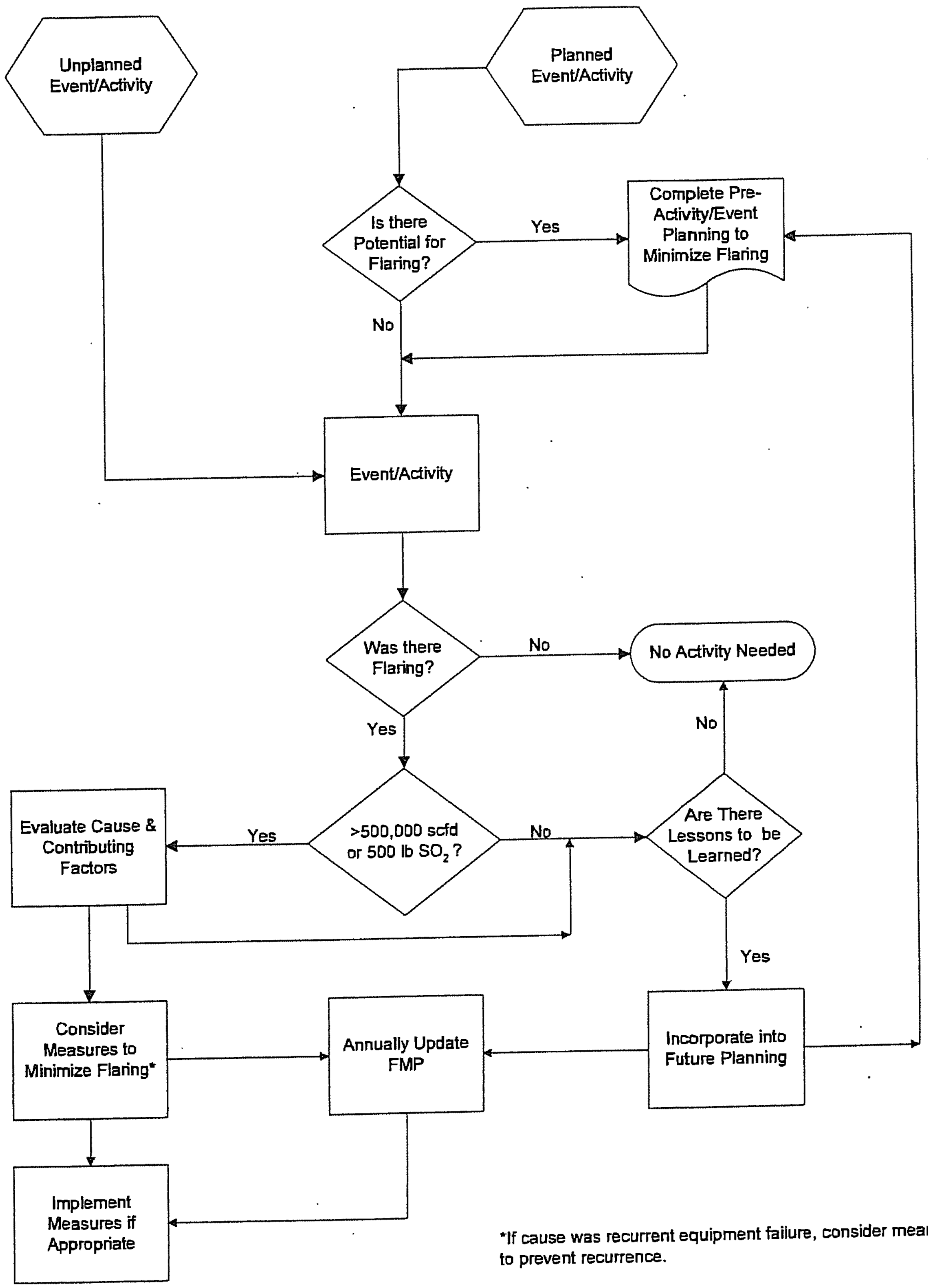
Unit Number	Unit Description
40	Raw Materials Receiving Unit
76	Gasoline Blending Unit
80	Refined Oil Shipping Unit
100	Process Water Unit
110	Hydrogen Plant
120	Hydrogen Plant (new in 2009, 3rd party operated by Air Liquide)
200	Coking Unit
200	Relief and Blowdown System
215	Gasoline Fractionation and Deisobutanizer, and Caustic Treating Unit
228	Isomerization Unit
229	Mid-Barrel Unionfining Unit
230	Naphtha Unionfining Unit
231	Magnaforming Unit
233	Fuel Gas Center
235	Sulfur Unit (new in 2009)
236	Sulfur Unit
238	Sulfur Unit
240	Unicracking Unit
244	Reforming Unit
246	Heavy Oil Hydrocracker (new in 2009)
248	Unisar Unit
250	Diesel Hydrotreating Unit
267	Crude Distillation Unit
MTC	Marine Terminal Complex
SPP	Steam Power Plant
---	Relief and Blowdown System

ATTACHMENT F

SAN FRANCISCO REFINERY

FLARE MINIMIZATION PROCESS FLOWCHART

Flare Minimization Flowchart

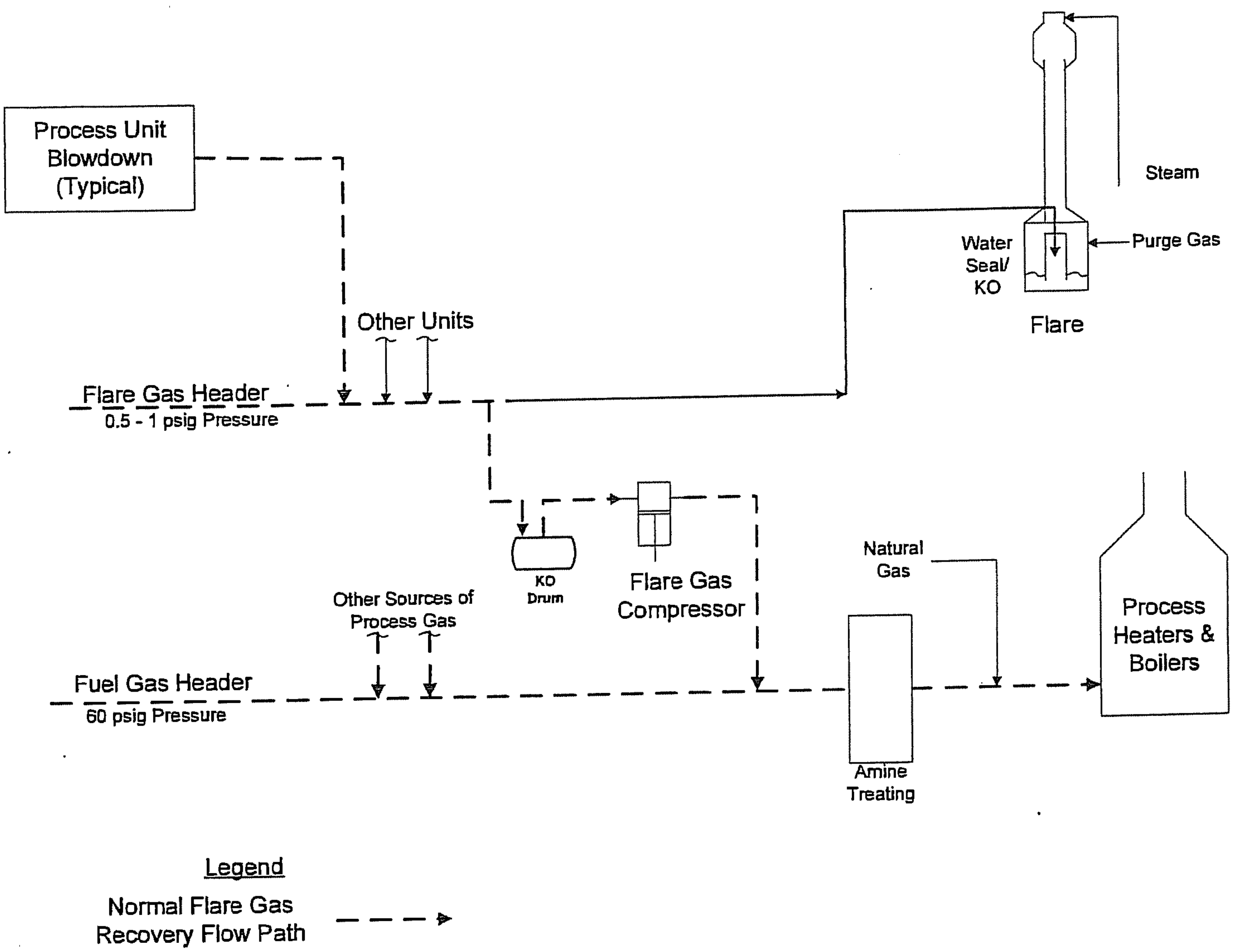


*If cause was recurrent equipment failure, consider means to prevent recurrence.

ATTACHMENT G

TYPICAL FLARE GAS RECOVERY SYSTEM

Typical Flare Gas Recovery System



ATTACHMENT H

SAN FRANCISCO REFINERY
FLARING EVENT OVERVIEW & CATEGORIZATION

Small Event Evaluation

Flare Gas Compressor (G 503/G 540) Capacity Exceedance

Year	Count	(MMSCF)	% of Total Flow	% of Non-RCA Flow
2004	34	0.89	0.38%	25.38%
2005	24	0.95	1.62%	28.87%
2006	19	0.27	0.39%	9.29%
2007	32	0.19	0.43%	13.96%
2008	64	1.43	5.87%	48.36%
2009	34	0.45	0.28%	2.71%
2010	24	0.33	0.92%	5.01%
2011	5	0.33	0.65%	4.97%
2012	8	0.14	0.10%	0.50%
2013	3	0.08	0.60%	0.80%
2014	0	0.00	0.00%	0.00%
2015	0	0.00	0.00%	0.00%
2016	0	0.00	0.00%	0.00%
2017	4	0.10	0.00%	0.00%
2018	0	0.00	0.00%	0.00%
2019	0	0.00	0.00%	0.00%
2020 to date	0	0.00	0.00%	0.00%

Fuel Gas Imbalance (<500,000 scfd)

Year	Count	(MMSCF)	% of Total Flow	% of Non-RCA Flow
Not individually tracked in past years.				
2009	15	12.38	7.81%	74.89%
2010	34	5.10	13.97%	76.34%
2011	23	2.21	4.37%	33.48%
2012	44	46.18	30.90%	16.20%
2013	16	2.22	17.30%	9.30%
2014	15	1.23	8.96%	41.95%
2015	58	8.38	11.99%	82.79%
2016	19	1.12	2.25%	29.91%
2017	6	0.98	11.03%	59.94%
2018	3	0.10	1.63%	3.80%
2019	11	0.44	1.99%	4.59%
2020 to date	4	0.29	4.17%	4.28%

All flare activity is carefully logged and the cause recorded in the majority of cases. This data is utilized to identify trends as well as tracking which flare events require Root Cause Analysis. This tracking tool helps to provide a means for analyzing the cause of all flaring. For the past few years for small events (<500,000 scfd) the majority of these events fell into two categories; 1) brief fuel gas recovery compressor capacity exceedances, 2) fuel gas imbalance. Listed below are a discussion of those categories of flaring.

A review of past flaring volumes since the installation of flowmeters was conducted. Based on the review, events which require RCA's per 12-12 constitute on average +80% of the total flow to the flare on an annual basis. A review of the events which don't require RCA was conducted per BAAQMD's request. In the past, the category with the most number of similar events is Fuel Gas Recovery Compressor Capacity Exceedances, but there has beennone of these events since 2014.

For 2011 - 2017 the highest category of small, non-RCA, events is fuel gas imbalance. In 2018 (year to date) there's only been one instance of this occurring. This typically occurs when fired sources such as heaters have been shutdown and there is excess fuel gas produced at the units. A tool was developed to assist in mitigating imbalances when possible and is described in the "Changes Made to Reduce Flare Emissions" under "Fuel System Diagnostic Tools – Developed tools for better fuel flow monitoring & optimization capability". In December 2011 a permit was submitted to change the Steam Power Plant (SPP) permit limit to allow for a higher ratio of refinery fuel gas to be combusted during periods of fuel gas imbalance. The permit application is pending review by BAAQMD and a U.S. EPA applicability determination. The potential LPG permit project will also help in reducing flaring due to fuel gas imbalance. In 2013, 2014 and 2015, efforts were made to reduce the materials entering into the fuel gas recovery system which helps reduce periods of potential fuel gas imbalance.

In 2012 and 2013 there were separate instances of leaking relief valves to the flare. The valve discovered leaking in 2012 had to be repaired on-line. In 2013 the leaking relief valve was reset through some operational moves. In both 2012 and 2013 the leaking relief valves constituted the highest volume of non-RCA flaring.

Attachment H

Prevention Measures
Listed in Causal Analysis Submitted to BAAQMD
& Recurrent Failure Analysis

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
6/1/2014	Unit 240 Plant 3 Instrument Upset	On June 1, 2014, an upset occurred at the Unicracker Plant 3 that affected the Refinery Fuel Gas "A" (RFG A) that is sent to the nearby third party Air Liquide Hydrogen Plant. Due to pressure and specific gravity fluctuations of the RFG A during the incident, Air Liquide shutout the RFG A gas as feed to their process. This resulted in the flaring of refinery fuel gas at the refinery. In addition, due to potentially high pressure in the fuel gas system, the G-503 Flare Gas Recovery Compressor was shutdown. This resulted in the flaring of scrubbed and unscrubbed gases	No alarms to indicate where the initial upset occurred. 3FIC019 showed flow even though valve was closed due to inaccurate meter reading (3FIC019 showed a reading of 11,500 BPD while valve output was 0%)	1. 3FIC019 immediate repair and restoration of accurate reading. 2. Set a low level output alarm for 3FIC019.OP. 3. Consider lowering high level alarm for 3LIC008 and associated level setpoint control.	1. COMPLETED June 1, 2014 2. COMPLETED 7/23/14 3. COMPLETED 7/23/14	Duration:6.83 hours Flow: 1,504 MSCF Emissions SO2 – 3,800 lbs (H2S = 1.52 %) NMHC – 1,041 lbs Methane – 224 lbs	• Reduced Consumption of Fuel Gas (4.2.1.3) • Upset/Malfunction (4.2.1.4) – fuel gas quality upsets • Emergency (4.2.1.5) – Local H_2S alarms near D-7 drum	225-14 N
			Inaccurate 3FIC019 reading and 3LIC008 level indicator float sticking - Conduct cleaning and calibration for 3FIC019 and other meters. Consider comprehensive review of Plant 3/RFG A system steam tracing.	Consider options for safe, routine cleaning of 3LIC008.	COMPLETED 9/23/14.			
			Air Liquide removal of RFG A from process feed. -.	Discuss strategies with Air Liquide for when RFG A feed is stopped to minimize impact to the Refinery fuel gas system	COMPLETED 9/9/2014			
			Sour water from D-7 automatically flushes to an open process sewer that can cause an H2S alarm - Initiation of a project to re-route the Unit 233 pressure control valve flare system tie-in location.	1a. Implement a project to re-route the Unit 233 pressure control valve flare system tie-in location. Install a tie-in location directly to the flare line downstream of 19F-3. (Connected with additional past Flare RCA's).	COMPLETED 12/2016 Relocated continuous purge on D-7			
9/25/2014	Unit 246 B-801 A/B Heater Shutdown	On September 25, 2014, the Unit 246 Heavy Gas Oil Hydrocracker had an upset which led to a brief, unscheduled, shutdown and subsequent startup of the Unit 246 B-801 A/B heater. During the shutdown, and subsequent startup, the refinery's flare gas recovery system could not compress all of the gas being sent to	G-826A speed transmitter, ST-313A, failure	Replace ST-313A	COMPLETED 10/2014	Duration: 3.0 hours Flow: 320 MSCF Emissions SO2 – 895 lb (H2S = 1.7%)	• Upset/Malfunction - Loss of Forced Draft Fan, G-826A (4.2.1.4) • Upset/Malfunction – Failure of instrumentation to function as designed (4.2.1.4)	341-14 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
		the flare. This resulted in the flaring of unscrubbed gas.				NMHC - 174 lb CH4 – 47 lb	• Maintenance, Turnaround, Startup, and Shutdown (4.2.1.1)	
9/30 – 10/1/2014	Removal of RFG A Feed to Air Liquide	On September 30, 2014 the third-party Air Liquide Hydrogen Plant took their feed gas coalescer out of service for a filter replacement. The differential pressure on the coalescer filter had been increasing. The filter replacement is done on a periodic basis to prevent a sudden increase in differential pressure. Feed gas referred to as RFG A flows through the coalescer from the Phillips 66 Rodeo Refinery to the Air Liquide Hydrogen Plant and then on to its Hydrogen Reformer. At approximately 10:50 AM RFG A was shutout by Air Liquide. This resulted in flaring of scrubbed gases due to fuel gas imbalance.	Air Liquide removal of RFG A from process feed.	Phillips 66 communicated with Air Liquide regarding the filter replacements. Phillips 66 and Air Liquide discussed having better communication prior to Air Liquide conducting the filter replacements and notifying appropriate refinery personnel so that flaring can be minimized or eliminated.	COMPLETED 10/2014	Duration: 27.58 hours Flow: 1,510 MSCF Emissions SO2 –142 lb (H2S = 0.06 %) NMHC - 1208 lb CH4 –289 lb	• Reduced Consumption of Fuel Gas (4.2.1.3) – Third Party Hydrogen Plant planned or unplanned maintenance on feed filters	342-14 Y
10/23/2014	Unit 240 Plant 2 Unplanned Shutdown	On October 23, 2014, Unit 240 Plant 2 had an upset which led to an unscheduled shutdown. At approximately 9:45 am, several alarms (common trouble, accelerometer and high vibration) occurred at the G-203A Hydrogen Makeup compressor. At 9:47 am, the G-203A machine was shut down and feed was pulled from the Unit. As part of the designed shutdown procedure, Unit 240 Plant 2 was depressured directly to the flare, bypassing the refinery's flare gas recovery system. During the depressuring process, the large amount of hydrogen from the Unit could cause fuel gas quality issues if it were sent to the flare gas recovery system, therefore the flare gas recovery system is bypassed. This resulted in the flaring of unscrubbed gas. In addition, during the upset, there were periods when the refinery's fuel gas system was out of balance and excess fuel gas was sent to the flare. This resulted in the flaring of scrubbed gas.	Failure of G-203A Hydrogen Makeup compressor second stage piston rod due to inadequate design.	Mitigate failure risk by eliminating flaw in heater hole by reducing stress riser; radius the bottom of the heater hole. Evaluate replacing the piston rods with the newer design.	COMPLETED 1/15/16	Duration: 7.1 hours Flow: 2,264 MSCF Emissions SO2 –2026 lb (H2S = 0.54 %) CH4 - 413 lb NMHC – 1313 lb	• Upset/Malfunction - Loss of Other Compressors, G-203A (4.2.1.4) • Maintenance, Turnaround, Startup, and Shutdown (4.2.1.1)	369-14 N
			Ineffective internal systems to ensure product reviews are reviewed for action.	Communicate the issue of product safety notices from Original Equipment Manufacturers to the Phillips 66 QA / QC manager.	COMPLETED 12/15/14			

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			Incomplete Operations notifications for Piston Rod Loading	Review and update notifications and alarming to prevent exceeding the maximum rod load of reciprocating compressors.	COMPLETED 8/24/15			
10/25 – 27/2014	Unit 240 Plant 2 Scheduled Maintenance	The primary cause of flaring was the Unit 240 Plant 2 reactors were being nitrogen purged in order to clear the reactors in preparation for planned maintenance and human entry. As part of the shutdown procedure, the unit was depressured directly to the flare, bypassing the refinery's flare gas recovery system by design. During depressuring, the large amount of hydrogen and nitrogen from the Unit could cause fuel gas quality issues if it were sent to the flare gas recovery system. This resulted in the flaring of gases containing mainly hydrogen or nitrogen with no significant sulfur. The reactor beds go through a hydrogen purge in which the excess hydrogen is sent directly to the flare. This purge is followed by a nitrogen purge which further removes VOCs from the catalyst bed in order to cool down the beds and make them safe for entry.	No prevention measures were identified in relation to the purging of the Unit 240 Plant 2 reactors because this activity is included in the Flare Minimization Plan (Section 4.2.1.1).	N/A	N/A	Duration: 51.25 hours Flow: 1,857 MSCF Emissions SO2 –202 lb (H2S = 0.01 %) NMHC - 281 lb CH4 – 94 lb	• Equipment Preparation for Maintenance – Depressurization of Equipment & Pressurization of Equipment with Nitrogen (Section 4.2.1.1).	358-14 N
10/29 -30/2014	Tank 205 Overfill and Odor Abatement System Compressors Shutdown	The primary cause of the flaring was that the G-503 flare gas recovery compressor was put into service as an OA compressor due to the failure of the OA system (A7) compressors. While G-503 was in OA service, there was insufficient capacity in the flare gas recovery system to recover all of the gases and the flaring of unscrubbed gas occurred. On October 29th, 2014, at approximately 1:25 pm, the OA system compressors shutdown. Excess liquid discovered in the line leading to the F-14 Knockout Pot in the OA system caused the OA compressors to shut down. As a result of the OA compressor shutdowns, pressure built up in several of the OA tanks causing them to exceed their atmospheric relief pressures. In order to minimize any potential odor impacts, the odor abatement flow was diverted to the flare system by putting the G-503 flare gas recovery compressor into OA service. During the period when the OA system was in an upset condition, there	Tank 205 Varec Level Gauge Failure	1. Install Radar Level Gauge to Provide Independent Level Verification 2. Implement a Reliability Program for Tank Gauging that Includes Planned Maintenance	1. COMPLETED 12/8/15 2. COMPLETED 1/2016	Duration: 51.25 hours Flow: 3,580 MSCF Emissions SO2 – 12,245lb (H2S = 2.1 %) NMHC - 1,488 lb CH4 –791 lb	• Upset/Malfunction - Loss of Odor Abatement Compressors (4.2.1.4) • Upset/Malfunction – Loss of Flare Gas Compressor – High Liquid Level (4.2.1.4)	375-14 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
		were no complaints received from the community. Phillips 66 maintenance crews were scheduled around the clock to repair the OA system. The liquid discovered in the OA system was determined to have originated from Tank 205, which stores sour water and slop oil. On October 29, the liquid in Tank 205 was filled to a level where the liquid could enter the OA system due to a faulty Varec gauge tank level reading. The Varec gauge is the instrument used to measure the level of the liquid in the tank and also provide alarms at predetermined liquid levels in the tank to ensure safe operation. The level reported by the Varec gauge was determined to be reporting a value at least 4 feet lower than the actual level in the tank on October 29. This led to Tank 205 being overfilled and liquid entering the OA system.						
			Hand Gauging of Tank 205 Level Inaccurate	Review, Modify and Improve Initial and Refresher Training and Operating Procedures for Hand Gauging	COMPLETED 12/11/16			
1/25-2/4/2015	Unit 246 Unplanned Shutdown – G-802 Compressor	On January 25, 2015, the Unit 246 Heavy Gas oil Hydrocracker (U246) shut down due to an unplanned shutdown and malfunction of the G-802 hydrogen gas recycle compressor (G-802). As part of the U246 shutdown procedure, gases are vented directly to the MP-30 flare, bypassing the flare gas recovery system. During this period, unscrubbed gas is sent to the flare. Due to the G-802 compressor being shutdown, the U246 reactors could not be cooled normally using G-802 to recycle gas through the system to cool the reactors without flaring. This process continued intermittently through February 4, 2015. The reactors were cooled by pressuring the system up with nitrogen and then depressuring the nitrogen and other gases in the reactors directly to the MP-30 flare. This results in the flaring of unscrubbed gas.	0.5 amp fuse not properly sized for reliable service	1. Replace 0.5 amp fuse with 2.0 amp fuse 2. Review all other fuses associated with this control system and panel for proper sizing. Replace improperly sized fuses as necessary.	1. COMPLETED 1/26/15 2. COMPLETED 1/26/15	Duration: 165 hours Flow: 14,247 MSCF Emissions SO_2 – 975 lb (H_2S = 0.04%) NMHC – 2272 lb CH_4 – 2244 lb	• Upset/Malfunction – Equipment failure which results in an immediate or controlled unit shutdown (e.g. recycle compressor failure) (4.2.1.4) • Maintenance, Turnaround, Startup, and Shutdown – Equipment Preparation for Maintenance, Depressuring and Purging (4.2.1.1)	080-15 Y
2/4-5/2015	Unit 246 Unplanned Shutdown – G-802 Compressor Seal Leak	The primary cause of the flaring was the shutdown of the G-802 compressor at Unit 246 due to a seal leak. During the shutdown, gases are vented directly to the MP-30 flare, bypassing the flare gas	G-802 dry gas seal installation procedure was not adequate.	Write a checklist procedure for dry gas seal installation on the U246 G-802 seals. Procedure should call out the appropriate seal drawing and require a craftsperson to mark each step as	COMPLETED 02/2015	Duration: 5 hours Flow: 643 MSCF Emissions	• Upset/Malfunction – Equipment failure which results in an immediate or controlled unit shutdown (e.g.	119-15 Y

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		recovery system and resulting in the flaring of unscrubbed gas. The shutdown of the G-802 recycle compressor was the result of a seal leak from the non-drive end (NDE) of the compressor that was identified during the startup of the compressor after maintenance. Prior to G-802 startup on February 4th, Phillips 66 personnel proactively replaced the entire compressor bundle with a warehouse spare bundle in response to a previous seal failure on the drive end (DE) of the compressor. The spare compressor bundle did not have mechanical seals installed on it so contractor millwrights specifically experienced with this type of equipment were directed to fully assemble the compressor bundle and install it in the G-802 compressor case. This work was completed prior to the event on February 4, 2015. The investigation into the NDE seal leak determined there were six missing socket head cap screws used to lock the seal rotating components around a set of split rings in order to set the seal axial position. The missing cap screws allowed a collar to move axially along the shaft when the seal gas purge supply was switched from nitrogen to recycle gas during the G-802 startup procedure. The collar contacted the bearing housing resulting in increased vibration levels for a short period of time during the startup process. As the collar contacted the bearing housing the seal moved axially and resulted in a seal leak being detected at the NDE of the compressor and the compressor was shutdown.		completed. This checklist will include all major components to install the seals including the socket head screws that were inadvertently omitted prior to the February 4th startup attempt.		SO2 –676 lb (H2S = 0.6 %) NMHC – 50 lb CH4 –80 lb	recycle compressor failure) (4.2.1.4)	
2/14/15	Unscheduled Unit 246 Shutdown – G-802 Compressor Tube Leak	The primary cause of the flaring was the unscheduled shutdown of Unit 246 due to the instrument tubing leak which caused the shutdown of the G-802 compressor. During the shutdown, gases are vented directly to the MP-30 flare, bypassing the flare gas recovery system and resulting in the flaring of unscrubbed gas. The shutdown of the G-802 recycle compressor was the result of a single 1/2-inch stainless steel (SS) tubing-to-fitting connection (gas seal supply-line connection 246:PDI-256) failure. While	Phillips 66 Maintenance Procedure (MP) 2.53, *Safe Assembly of Tubing Connections Guideline,* not followed and not well understood by contractors.	1. Conduct refresher training on MP 2.53 with P66 and contractor instrument technicians, pipe fitters and machinists. 2. Audit training records for those performing instrument tubing assembly per MP 2.53 requirements	1. COMPLETED 6/26/15 2. COMPLETED 5/28/15	Duration: 1 hours Flow: 1,118 MSCF Emissions SO2 – 1,178 lb (H2S = 0.6 %) CH4 –125 lb NMHC – 77 lb		110-15 Y

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		Unit 246 was shutdown due to previous unscheduled events (see RCA for February 4, 2015 event), work was scheduled to disassemble instrument tubing connections between the G-802 compressor gas seal system and recycle compressor to install block valves ahead of the pressure gauges on the instrument panel. The block valves were installed to allow maintenance on the pressure gauges with G-802 in operation. However, upon startup, one of the instrument tubing-to-fitting connections failed which resulted in the release of high pressure hydrogen to atmosphere.						
			MP 2.53 requires 20% visual verification of fitting connections. The consequence of failure of a Highly Hazardous Service (defined in MP 2.53) may be very significant.	Revise MP 2.53 to require 100% visual verification of instrument tubing assemblies for all connections in Highly Hazardous Service.	COMPLETED 6/26/15			
3/5-6/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas consumers, during maintenance periods on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures were implemented but measures were taken to minimize the quantity of material flared.	N/A	N/A	Duration: 40 hours Flow: 1422 MSCF Emissions SO2 – 15 lb (H2S = 0.01%) CH4 –272 lb NMHC –1148 lb	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	136-15 N
3/12-14/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas consumers, during maintenance periods on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures were implemented but measures were taken to minimize the quantity of material flared.	N/A	N/A	Duration: 28 hours Flow: 2393 MSCF Emissions SO2 – 40 lb (H2S =0.01 %) CH4 –627 lb NMHC – 2193lb	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	137-15 N
3/22/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures	N/A	N/A	Duration: 16.5 hours Flow: 501 MSCF	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	138-15 N

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		consumers, during maintenance periods on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	were implemented but measures were taken to minimize the quantity of material flared.			Emissions SO2 – 8 lb (H2S =0.01 %) CH4 –141 lb NMHC – 470 lb		
3/26/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas consumers, during maintenance periods on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures were implemented but measures were taken to minimize the quantity of material flared.	N/A	N/A	Duration: 11 hours Flow: 679 MSCF Emissions SO2 – 11 lb (H2S =0.01 %) CH4 –185 lb NMHC – 607 lb	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	139-15 N
4/19/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas consumers, during maintenance periods on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures were implemented but measures were taken to minimize the quantity of material flared.	N/A	N/A	Duration: 12.25 hours Flow: 786 MSCF Emissions SO2 – 13 lb (H2S =0.01 %) CH4 –239 lb NMHC – 741 lb	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	167-15 N
5/18-19/15	Unscheduled Unit 240 Plant 2 Shutdown – D-203 High Temperature	On May 18, 2015, the Unit 240 Plant 2 Hydrocracker (U240) had an unplanned shut down due to a high temperature in the U240 D-203 2nd stage reactor. As part of the U240 shutdown procedure, gases are vented directly to the Main flare, bypassing the flare gas recovery system. During this period, unscrubbed gas is sent to the flare.	Failure of the D-203 TV-023 quench valve positioner.	Consider upgrading the D-203 quench valve positioners with newer design.	COMPLETED 2/19/16	Duration: 19 hours Flow: 5,676 MSCF Emissions SO2 – 10,170 lb (H2S =0.01 %) CH4 –1,132 lb NMHC – 4,487 lb		176-15 N
5/22/15	Maintenance Gas Turbine – Fuel Gas Balance	Maintenance turnarounds were taking place on the gas turbines at the Steam Power Plant (SPP). Because the gas turbines at the SPP are large fuel gas consumers, during maintenance periods	Maintenance pre-planning was conducted that identified the potential for fuel gas imbalance. No specific prevention measures were implemented but measures	N/A	N/A	Duration: 19.5 hours Flow: 1590 MSCF Emissions	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	189-15 N

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		on these turbines there were periods where all of the fuel gas produced at the refinery could not be consumed. Due to the imbalance in the fuel gas system, the additional fuel gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas and natural gas was flared.	were taken to minimize the quantity of material flared.			SO2 – 26 lb (H2S =0.01 %) CH4 –405 lb NMHC – 1560 lb		
10/3/15	G-401B A-Gas Compressor Unscheduled Maintenance	On October 2, 2015, Phillips 66 noticed that proper lubrication was not getting to the G-401B compressor. This compressor is used to provide feed gas (A-Gas) to the third-party Air Liquide Hydrogen Plant, which is a large consumer of fuel gas. Due to the loss of proper lubrication, the G-401B compressor needed to be shut down while repairs were made to the lube oil system. During the shutdown of this compressor, the A-Gas normally sent to Air Liquide had to be consumed at the refinery. Due to the imbalance in the fuel gas system, the additional A-Gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas was flared.	G-401B Compressor Lube Oil System Failure	The lube oil system was cleaned out and the filter was replaced.	COMPLETE 10/3/15	Duration: 15 hours Flow: 1252 MSCF Emissions SO2 – 20 lb CH4 – 535 lb NMHC – 650 lb	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	352-15 N
11/2–4/15	PG&E Voltage Sag – Unit 246 and U240 Plant 2 Shutdown	On November 2, 2015 at approximately 4:10 PM a PG&E transmission line had a fault caused by lightning in the area. The fault led to a voltage sag in a portion of the power provided to the Refinery. As a result of the voltage sag, the Unit 240 Plant 2 G-201 Charge Pump (G-201) and the Unit 246 G-803 A and B H_2 Recycle Compressors (G-803 A/B) shutdown. The loss of G-201 caused a shutdown of Unit 240 Plant 2. During shutdown of Unit 240 Plant 2, unscrubbed gas was sent to the Main flare. The loss of the G-803 A/B compressors led to the shutdown of Unit 246. During the event, unscrubbed gas was sent to the Main flare and MP-30 flare. Due to potentially high pressure in the fuel gas system, the G-503 Flare Gas Recovery Compressor was shutdown. This resulted in the flaring of scrubbed and uncscrubbed gases.	PG&E Voltage Sag.	Communicate with PG&E regarding equipment upgrades that may be possible by them to reduce time and severity of voltage sags.	COMPLETED 4/26/16	Duration: 42 hours Flow: 29,470 MSCF Emissions SO2 – 20,474 CH4 – 3,259 NMHC- 4,949	• Upset/Malfunction – Equipment failure which results in an immediate or controlled unit shutdown (4.2.1.4) • Upset/Malfunction – Loss of a utility (power) (4.2.1.4) • Emergency (4.2.1.5) – Local H2S alarms near D-7 drum	358-15 N
			G-201 starter motor failed.	Perform checks on starter motor.	COMPLETED 3/12/16			
			G-803 A/B motor tripped.	Verify the G-803 A/B motor trip settings.	COMPLETED 4/26/16			
			Sour water from D-7 automatically flushes to an open process sewer that can cause an H2S alarm.	Initiation of a project to re-route the Unit 233 pressure control valve flare system tie-in location. Install a tie-in location directly to the flare line downstream of 19F-3. (Connected with additional past Flare RCA's).	COMPLETED 12/2016 Relocated continuous purge on D-7			
1/9-11-16	Unit 240 and 246 Planned Shutdown	On January 9, 2016 Unit 240 and Unit 246 were being shut down for maintenance work. As part of the unit shutdown, and	No new prevention measures or corrective actions were identified. These activities were planned	N/A	N/A	Duration: 27 hours Flow: 3,107 MSCF	• Maintenance, Turnaround, Startup, and Shutdown – Equipment	118-16 N

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		to prepare for maintenance and entry, both units were depressured and purged. The purged material was vented directly to the Main Flare for Unit 240 and the MP-30 Flare for Unit 246 and resulted in the flaring of unscrubbed gases.	maintenance activities that will re-occur in the future.			Emissions (lb) SO2 – 51 CH4 – 132 NMHC- 91	Preparation for Maintenance, Depressuring and Purging	
1/17-18/16	Unit 250 Unscheduled Shutdown – Feed Filters	On January 17, 2016 at approximately 00:20 AM, the feed filters at the Unit 250 Diesel Hydrotreater (U250) began to indicate a rapid increase in the pressure drop across the filters. The increase in pressure indicated that the filters were plugging and feed was pulled from U250. Due to the shutdown of U250, the refinery hydrogen header pressure increased and excess hydrogen was sent to the flare gas recovery system. Because the G-503 flare gas recovery compressor cannot compress large amounts of hydrogen and excess hydrogen in the fuel gas system can cause fuel gas issues which can affect safe operation of refinery heaters, the flare gas recovery system was taken off-line. As a result, unscrubbed gas was sent to the Main Flare beginning at approximately 01:25 AM.	Feed Quality at U250.	Develop procedure to require the U250 feed line from U200 to be flushed/cleared after certain U200 upsets.	COMPLETED 8/31/16	Duration: 43 hours Flow: 13,188 MSCF Emissions (lb) SO2 –21,494 CH4 – 2,340 NMHC- 2,819	• Upset/Malfunction – Feed quality issue which results in Unit shutdown (4.2.1.4) • Upset/Malfunction – Hydrogen sent to flare system.	082-16 N
1/22 – 23/16, 2/1 – 2/2/16	Planned startup and shutdown of the F-45 Flare System Blowdown Drum	Flaring of uncrubbed gas not recovered by the flare gas recovery system (FGRS) occurred as a result of the planned startup and shutdown of the F-45 Flare System Blowdown Drum (F-45). During the period of time while F-45 was in the process of shutting down and starting up, the FGRS is required to be shutdown. In order to isolate and shutdown F-45, the entire flare system must be lined up to the MP-30 flare instead of the Main Flare. During the process of switching over, and when all gases are being routed to the MP-30 flare, the FGRS compressors must be taken off line. No recovery of gases sent to the flare system is possible during this time and unscrubbed gas was flared. After F-45 was isolated and shutdown, the flare system was re-routed back to the Main Flare (instead of the MP-30 Flare) and the FGRS was put back on-line and the flaring ceased. The shutdown activities and associated flaring described above occurred on January 22nd and 23rd, 2016. After the maintenance and required inspections on F-45 were completed, the	Maintenance on portions of the flare system must occur periodically to ensure reliable operation, and therefore, no prevention measures or corrective actions to prevent recurrence other than the measures taken as described in this report and contained in the Phillips 66 Flare Minimization Plan.	N/A	N/A	Duration: 51 hours Flow: 6,651 MSCF Emissions (lb) SO2 – 9,817 CH4 – 2,205 NMHC- 1,783	• Maintenance, Turnaround, Startup, Shutdown – Equipment Preparation for Maintenance & Working on Equipment (Section 4.2.1.1)	097-16 N

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		entire flare system was again lined up to the MP-30 flare to allow for the safe startup of F-45 and return it to service. While the flare system was lined up to the MP-30 Flare, no flare gas recovery is possible and unscrubbed gas was flared. After F-45 was returned to service, the flare system was re-routed back to the Main Flare and the FGRS was put back on-line and the flaring ceased. These startup related activities occurred on February 1st and 2nd, 2016.						
2/10-12/16	Unit 246 Startup	During activities related to startup of Unit 246, one of the reactor depressuring valves was leaking as Unit 246 was being put back into service. This valve is designed to be vented directly to the MP-30 flare. By venting directly to the flare, the potential need to shut down the Flare Gas Recovery Compressor(s) is prevented and overall flare emissions are minimized. Because of the leaking depressure valve, unscrubbed gases were sent to the flare. However, no H2S was detected in the lab analysis of the flare gas.	Depressure valve at Unit 246 leaking during startup.	Stop leak from depressure valve to allow startup of Unit 246.	COMPLETE 2/12/16	Duration: 34 hours Flow: 2,302 mSCF Emissions (lb) SO2 – 37 CH4 – 645 NMHC- 99	• Upset/Malfunction – Leaking relief valve (4.2.1.4)	161-16 N
2/12/16	G-501 Wet Gas Compressor Shutdown	At approximately 5:12 AM on February 12, 2016 the G-501 Wet Gas Compressor (G-501) had an unscheduled shut down. The gas from the Unit 200 Bubble Tower which is normally recovered by G-501 was subsequently relieved to the refinery flare gas recovery system (FGRS). Due to the excess gas normally recovered by G-501, the FGRS could not recover the additional process gas resulting in flaring of unscrubbed gas. After review and evaluation of the G-501 compressor shutdown, the compressor was restarted at approximately 9:05 AM and flaring subsided shortly thereafter.	G-520 lube oil pump bearing failure	1. Relocate the location for vibration readings on the G-520 and G-520A lube oil pumps to optimize the vibration measurements on the bearings. 2. Replace G-520 pump bearing and rotors.	1. COMPLETED 2/2016 2. COMPLETED 2/2016	Duration: 4 hours Flow: 2,294 MSCF Emissions (lb) SO2 – 9,420 CH4 – 803 NMHC- 1,084	• Upset/Malfunction – Loss of major compressor, G-501 Wet gas Compressor (4.2.1.4)	113-16 N
			G-G20A failed to auto-start	Test and calibrate pressure switch for Auto-start.	COMPLETED 2/2016			
2/14-15/16	Unit 246 Catalyst Pre-sulfiding	Beginning on February 14, 2016, maintenance activity at the Unit 246 Hydrocracker resulted in higher than typical sulfur concentrations in the refinery fuel gas (RFG). Due to the higher than typical sulfur concentrations in the RFG, refinery personnel reduced RFG consumption at the gas turbines at the Steam Power Plant (SPP) to meet SPP permit conditions which limit SO2	No new prevention measures or corrective actions were identified. These activities were planned maintenance activities that will re-occur in the future.	N/A	N/A	Duration: 32 hours Flow: 7,601 MSCF Emissions (lb) SO2 – 665 CH4 – 1,930 NMHC- 4,124	• Maintenance, Turnaround, Startup, and Shutdown – Fuel Balance	123-16 N

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		emissions. The reduction in consumption of RFG at the SPP resulted in excess RFG being sent to the flare. This resulted in the flaring of scrubbed gas with higher than typical sulfur concentrations. In addition, at approximately 2:11 pm on February 14, 2016, the SPP C turbine experienced an unscheduled shutdown. This resulted in additional excess RFG that was sent to the flare and increased the amount of scrubbed gas that was flared.						
2/22-23/16	Unit 240 Scheduled Start Up	On February 22 and 23, 2016 Unit 240 was in the process of startup after being shut down for planned maintenance work. As part of the startup, recycle gases and other gases were vented to the Flare Gas Recovery System. This contributed to the flaring of excess refinery fuel gas.	No new prevention measures or corrective actions were identified. These activities were planned maintenance activities that will re-occur in the future.	N/A	N/A	Duration: 17.5 hours Flow: 3,188 MSCF Emissions (lb) SO2 – 53 CH4 – 758 NMHC- 1,711	• Maintenance, Turnaround, Startup, and Shutdown – Unit Startup (4.2.1.1)	162-16 N
2/25/16	U240 D-302 Depropanizer overhead sent to the flare gas recovery system during startup	On February 25, 2016, flaring occurred intermittently from approximately 1:00 PM until 4:00 PM due to process upsets which occurred during the startup of the Unicracker Complex (Units 240, 244, 246 and 248). During the startup of Unit 240 (U240), feed swings led to overhead material (primarily light hydrocarbons – butane and propane) from the U240 D-302 Depropanizer being sent to the flare gas recovery system (FGRS). The additional gas in the FGRS caused the fuel gas system to increase pressure and relieve treated refinery fuel (RFG) to the flare, resulting in the flaring of scrubbed gas. In addition, as the pressure in the fuel gas system continued to increase due to the overhead material from U240 D-302, the FGRS was taken off-line and circulated. This resulted in the flaring of unscrubbed gases.	Failure of D-302 LIC003 Level Indicator	Maintenance completed on LIC003. Instrument reading accurately.	COMPLETED 2/25/2016	Duration: 2 hours Flow: 380 MSCF Emissions (lb) SO2 – 1,123 CH4 – 91 NMHC- 262	• Upset/Malfunction – Failure of instrumentation to function as designed (4.2.1.4) • Maintenance, Turnaround, Startup, and Shutdown – Fuel Balance • Emergency (4.2.1.5) – Local H2S alarms near D-7 drum	144-16 N
			Sour water from D-7 automatically flushes to an open process sewer that can cause an H2S alarm.	Initiation of a project to re-route the Unit 233 pressure control valve flare system tie-in location. Install a tie-in location directly to the flare line downstream of 19F-3. (Connected with additional past Flare RCA's).	COMLPETED 12/2016 Relocated continuous purge on D-7			
3/12-13/16	Unscheduled shutdown of the G-202 Hydrogen	On March 12, 2016, the Unit 240 Plant 2 Hydrocracker (U240) had an unscheduled shut down due to the	G-202 Seal oil Level Controller LCV-208 Not Operating Correctly	Valve positioner on LCV-208 replaced. Instrument reading accurately.	COMPLETED 3/12/2016	Duration: 22.5 hours Flow: 1509 MSCF	• Upset/Malfunction – Failure of instrumentation to function as designed (4.2.1.4)	159-16 N

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	Recycle Compressor	shutdown of the G-202 Hydrogen Recycle Compressor (G-202). As part of the U240 shutdown procedure, gases are vented directly to the Main flare, bypassing the flare gas recovery system. During this period, unscrubbed gas is sent to the flare.				Emissions (lb) SO2 – 622 CH4 – 153 NMHC- 496		
3/14-15/16	Unscheduled Shutdown of Unit 246 - G-802 recycle gas compressor	On March 14, 2016, there was intermittent flaring at the Main and MP-30 flares related to the unscheduled shutdown of the Unit 246 Heavy Gas Oil Hydrocracker (Unit 246). This led to the flaring of both scrubbed and unscrubbed gas.	Isolation valve 246XV045 on U246 G-802 failed closed.	Replaced the solenoid that failed which caused the isolation valve to close.	COMPLETED 3/14/16	Duration: 27 hours Flow: 4806 MSCF Emissions (lb) SO2 –327 CH4 – 1004 NMHC- 1703	• Upset/Malfunction – Loss of other compressors (recycle hydrogen) (4.2.1.4)	181-16 N
6/28/16	Unscheduled shutdown of the flare gas recovery compressors, G-503 and G-540 A, B and C	The primary cause of the flaring was the unscheduled shutdown of the flare gas recovery compressors, G-503 and G-540 A, B and C (G-540 ABC). When these compressors are shutdown, gases normally recovered and sent to the refinery fuel gas (RFG) system are sent to the flare. The G-503 recovery compressor shutdown due to high liquid level in the interstage knockout pot of the compressor. The G-540 ABC recovery compressors shutdown due to high suction temperature.	No alternate cooling during Coker steam out if G-52 is not operating.	Complete tie-ins for alternate cooling facilities during Coker steam out.	COMPLETED 10/25/16	Duration: 4 hours Flow: 574 MSCF Emissions (lb) SO2 – 715 CH4 – 195 NMHC- 289	• Upset/Malfunction – Loss of flare gas recovery compressors; high inlet temperature and high liquid level (4.2.1.4) • Upset/Malfunction – Loss of a utility; cooling water (4.2.1.4)	258-16 N
1/9-13/16	Unit 250 Scheduled Shutdown	On January 9 through 12, 2017, process vessels at the Unit 250 Diesel Hydrotreater (Unit 250) were purged and cooled with nitrogen as part of the planned shutdown and maintenance of Unit 250. During this period, nitrogen was used to purge gases from the unit and cool equipment. These gases were directed to the flare and bypassed the flare gas recovery system.	No new prevention measures or corrective actions were identified. The maintenance at Unit 250 is a planned activity that will re-occur in the future.	N/A	N/A	Duration: 70.25 hours Flow: 4,452 MSCF Emissions (lb) SO2 – 85 CH4 – 47 NMHC - 144	• Maintenance, Turnaround, Startup, and Shutdown – Unit Startup (4.2.1.1)	070-17 N
1/22/17	Unscheduled Shutdown of Unit 246 - G-814 Charge Pump	On 1/22/2017 at approximately 3:23 PM, the G-814 hydrocracker charge pump (G-814) at Unit 246 failed which caused an unscheduled shutdown of the unit. The emergency isolation valve (246XY032) on the suction of G-814 closed due to a suspected solenoid failure which caused an automatic shutdown of G-814 on low flow. Due to the shutdown of G-814, the Unit 246 reactors depressured gas directly to the flare resulting in the flaring of	Solenoid failure on Isolation valve 246XY032 on U246 G-814 failed closed.	Change operation of solenoid so that it is energized to close the isolation valve. If solenoid fails, valve will remain open.	COMPLETED 2/22/17	Duration: 2.2 hours Flow: 1,309 MSCF Emissions (lb) SO2 – 486 CH4 – 62 NMHC - 155	• Upset/Malfunction – Loss of other compressors (recycle hydrogen) (4.2.1.4)	089-17 N

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		unscrubbed gas. In addition, during the shutdown of Unit 246, gases were also vented to the flare gas recovery system (FGRS) which led to an excess amount of refinery fuel gas (RFG). Due to the excess amount of RFG, scrubbed gas was also flared.						
7/8/17	Unscheduled Shutdown of G-401 A/B Compressors	On July 8, 2017, at approximately 2:20 PM, a grass fire started along Interstate 80E and proceeded into Phillips 66 property, near the refinery's seasonal storage tanks. The fire quickly moved to an adjacent field, where PG&E high power lines pass that feed into the Refinery electrical system. Power was lost from one of four feeder line's supplying the Refinery which led to shutdown of several pieces of equipment, including the G-401 A/B compressors. These compressors are used to provide feed gas (A-Gas) to the third-party Air Liquide Hydrogen Plant, which is a large consumer of fuel gas. During the shutdown of the compressors, the A-Gas normally sent to Air Liquide had to be consumed at the refinery. Due to the imbalance in the fuel gas system, the additional A-Gas that could not be consumed by the refinery process heaters was flared. During this period, only excess scrubbed fuel gas was flared.	Power loss led to equipment shutdown.	Investigate options, such as time delay, to prevent shutdown of the G-401 A/B compressors during brief power dips.	This item was evaluated and determined not to be implemented as it would not have been beneficial in preventing this flaring event.	Duration:6.5 hours Flow: 545 MSCF Emissions (lb) SO2 – 9 CH4 – 210 NMHC - 268	• Reduced Consumption of Fuel Gas – Fuel Gas Imbalance (Section 4.2.1.3)	295-17 N
7/10/17	Unit 240 Plant 2 Scheduled Shutdown	On July 10, 2017, process vessels at Unit 240 Plant 2 (Unit 240-2) were purged and cooled with nitrogen as part of the planned shutdown and maintenance of the Unit. During this period, nitrogen was used to purge gases from the unit and cool equipment. These gases were directed to the flare and bypassed the flare gas recovery system. The primary cause of the flaring was the scheduled shutdown of Unit 240-2. During purging and cooling, nitrogen is sent directly to the Main Flare. During this time, the only gases flared are those gases remaining in the process unit and the nitrogen used to purge the unit.	No new prevention measures or corrective actions were identified. The maintenance at Unit 240-2 is a planned activity that will re-occur in the future.	N/A	N/A	Duration: 12.1 hours Flow: 1,286.5 MSCF Emissions (lb) SO2 – 12 CH4 – 287 NMHC – 89	• Maintenance, Turnaround, Startup, Shutdown – Equipment Preparation for Maintenance (Section 4.2.1.1)	283-17 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
11/11/18	G-501 Wet Gas Compressor Unplanned Shutdown	At approximately 6:38 AM on November 11, 2018 the G-501 Wet Gas Compressor (G-501) had an unscheduled shutdown. The unplanned shutdown occurred during the Unit 200 startup following a turnaround. Following the G-501 shutdown, the gas from the Unit 200 Bubble Tower, which is normally recovered by G-501, was subsequently relieved to the refinery flare gas recovery system (FGRS). Due to the excess gas normally recovered by G-501, the FGRS could not recover the additional process gas resulting in flaring of unscrubbed gas. Following troubleshooting of the G-501 compressor shutdown and subsequent control repairs, the compressor was restarted at approximately 1:50 PM and flaring subsided shortly thereafter. The primary cause of the flaring was the unscheduled shutdown of G-501, which caused excess gas to be sent to the FGRS. The amount of gas being sent to the FGRS exceeded the recovery capacity of the system and the excess was flared. Upon investigation, it was discovered that the G-501 Wet Gas Compressor shutdown due to a motor high amperage (AMPs) safety shutdown activation. Motor AMPs are an indication of load being pulled on a compressor.	1. G-501 Replacement Motor Protective Relay Installed was not configured for existing analog signal -	Replacement motor protective relay was re-configured to transmit the necessary analog signal so that AMP levels could be transmitted to the Distributed Control System (DCS) for monitoring and alarms.	COMPLETED 11/11/18	Duration: 8.2 hours Flow: 1,182 MSCF Emissions (lb) SO2 – 4,179 CH4 – 445 NMHC – 591	• Upset/Malfunction – Loss of major compressor, G-501 Wet gas Compressor (4.2.1.4)	371-18 N
			G-501 Compressor Shutdown Limit Enhancement	A suction pressure operating guideline will be incorporated into the Unit 200 start-up procedure to note the 15 psi limit (approximate).	COMPLETED 4/16/19			
12/7/18	G-503 Flare Gas Recovery Compressor Unplanned Shutdown	At approximately 2:00 AM on December 7, 2018 the G-503 Flare Gas Recovery Compressor (G-503) had an unscheduled shutdown. Flare activity continued until repairs were made and the Compressor was restarted. The flaring ended at approximately 3:24 PM. on the second stage suction knock-out pot. The level indicator is an equipment safety protection device. Following the shutdown, the knock-out pot was examined and no liquid was found in the sight glass. Maintenance personnel were called out to examine potential compressor instrument failures. Initially a lube oil pressure switch was replaced.	G-503 shutdown due to faulty high liquid level indication in the second station suction knock-out pot.	1.Lube oil pressure switch replacement 2. Replacement of faulty coil in the motor circuitry.	COMPLETED 12/7/18 COMPLETED 12/7/18	Duration: 13.6 hours Flow: 2,451 MSCF Emissions (lb) SO2 – 2,075 CH4 – 623 NMHC – 990	• Upset/Malfunction – Loss of flare gas compressor (p. 4-29) • Upset/Malfunction – Failure of instrumentation to function as designed (p. 4-19)	030-19 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
		Replacement of the lube oil pressure switch alone did not allow the G-503 compressor to be restarted. A faulty coil in the motor circuitry was later determined to be the cause of the false high liquid level indication and the faulty coil was replaced. The replacement of the faulty coil allowed the G-503 compressor to be restarted.						
3/25/19	Fuel Gas Upset – Flaring Fuel Gas to SPP	A fuel gas upset occurred on March 25, 2019 that resulted in hydrogen sulfide (H_2S) in the refinery fuel gas (RFG) to be at estimated concentrations greater than the 162 ppm (3-hour average) regulatory limit. Due to the higher-than-typical sulfur concentrations in the RFG, refinery personnel reduced RFG consumption at the Steam Power Plant (SPP) gas turbines to meet SPP federally enforceable permit conditions that limit SO_2 mass emissions. The reduction in consumption of RFG at the SPP resulted in excess RFG being sent to the flare. This resulted in the flaring of partially scrubbed gas with higher-than-typical sulfur concentrations.	1. Lack of anti-foam in DGA system.	Replaced pump with spare.	COMPLETED 3/26/19	Duration: 22.86 hours Flow: 1,726 MSCF Emissions (lb) SO2 – 317 CH4 – 500 NMHC – 1,377	• 4.2.1.4 Upset/Malfunction – Fuel Gas Quality Upsets	151-19 N
			2. Foaming in DGA resulting in loss of H_2S stripping efficiency.	Add additional alarms to provide early indication when foaming may be occurring.	COMPLETED 6/21/19			
4/23/19	3rd Party Hydrogen Plant shutdown due to faulty component on PSA valve	On April 23, 2019 at approximately 5:50 PM the Air Liquide Hydrogen Plant located next to the refinery experienced a sudden unplanned shutdown. Off-gas produced at the Phillips 66 Rodeo Refinery which is referred to as RFG A is a process feed to the Air Liquide Hydrogen Plant Hydrogen Reformer. Due to the sudden, unplanned shutdown the RFG A was not being utilized as feed by the Air Liquide Plant. This resulted in flaring of scrubbed RFG A gas. In addition, due to the sudden loss of a large volume of Hydrogen which supports the refinery process units this resulted in upset conditions for a number of units as well as fuel gas imbalances due to the sudden change in demand for refinery fuel gas.	Unplanned shutdown due to faulty component on PSA valve.	Faulty valve component identified and replaced prior to 3rd party hydrogen plant restart.	COMPLETED 4/24/19	Duration: 7.63 hours Flow: 1,048 MSCF Emissions (lb) SO2 – 18 CH4 – 267 NMHC – 676	• Fuel and Hydrogen Gas Balance (4.2.1.1) – Unplanned Hydrogen supplier shutdowns	152-19 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
9/25/2019	G-501 Wet Gas Compressor (G-501) experienced an unplanned shutdown.	At approximately 9:56 AM on September 25, 2019 the G-501 Wet Gas Compressor (G-501) experienced an unplanned shutdown. Following the G-501 shutdown, the gas from the Unit 200 Bubble Tower, which is normally recovered by G-501, was subsequently relieved to the refinery flare gas recovery system (FGRS). Due to the excess gas normally recovered by G-501, the FGRS could not recover the additional process gas resulting in flaring of unscrubbed gas. Per site procedures, steps were taken to put the G-503 flare gas recovery compressor in G-501 Wet Gas Recovery Compressor (WGC) service in order to reduce flow to the flare. Due to challenges in returning G-501 WGC to service it was determined to shut the Unit 200 Coker process unit down to cease flaring rather than wait for the G-501 WGC operation to be restored. Flaring stopped at 6:58 PM when the G-503 flare gas recovery compressor was returned back into flare gas recovery service.	1. Controller operation in unusual mode.	Identify and enhance means to communicate unusual modes of operation for critical controllers, such as WGC spillback in manual.	COMPLETED 2/28/20	Duration: 9:02 Flow: 1,983 Emissions (lb) SO2 – 7,082 CH4 – 511 NMHC – 1,474	• Upset/Malfunction – Loss of major compressor, G-501 Wet gas Compressor (4.2.1.4)	355-19 N
			2. Upon the initial shutdown of the G-501 compressor it would not immediately restart. It was found the starter electrical connections were bad which prevented rapid restart. The cause of the bad electrical connection is unknown, but it is potentially due to high AMP operation or some issue that occurred following the November 2018 startup following unit turnaround.	Replace components of the electrical starter to allow G-501 to restart.	**COMPLETED** 9/25/19			
			3. There was not heightened awareness that this AMP alarm may indicate G-501 shutdown nor that the compressor may be operating in an abnormal mode of operation.	Review and update the G-501 alarm set points to ensure proper notification of potential equipment shutdown.	**COMPLETED** 9/26/2019			
10/3/19	Unit 246 planned shutdown	On October 3, 2019 Unit 246 was being shut down for maintenance work. As part of the unit shutdown, and to prepare for maintenance and entry, the unit was depressured and purged. The purged material was vented directly to the MP-30 Flare which resulted in the flaring of unscrubbed gases.	No new prevention measures or corrective actions were identified. These activities were planned maintenance activities that will re-occur in the future.	N/A	N/A	Duration: 32:45 Flow: 4,771 Emissions (lb) SO2 – 65 CH4 – 1,427 NMHC –861	• Maintenance, Turnaround, Startup, and Shutdown – Equipment Preparation for Maintenance, Depressuring and Purging	398-19 N
10/21/19	Unit 240 Plant 2 Planned Shutdown	On October 21, 2019 Unit 240 Plant 2 was being shut down for maintenance work. As part of the unit shutdown, and to prepare for maintenance and entry, the unit was depressured and purged. The purged material was vented directly to the Main Flare which resulted in the flaring of unscrubbed gases.	No new prevention measures or corrective actions were identified. These activities were planned maintenance activities that will re-occur in the future.	N/A	N/A	Duration: 9:07 Flow: 691 Emissions (lb) SO2 – 12 CH4 – 477 NMHC –59	• Maintenance, Turnaround, Startup, and Shutdown – Equipment Preparation for Maintenance, Depressuring and Purging	399-19 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
10/30/19	Main Flare turnaround and F-3 vessel inspection	Beginning on October 30, 2019 a planned shutdown was conducted on the Main Flare (S-296) and equipment associated with the flare. The purpose of the shutdown was to conduct preventative maintenance work on the Main Flare and to conduct a required vessel inspection on the F-3 Water Seal drum on the Main Flare system. To remove the flare equipment from service chemical cleaning and steaming was performed to remove residual hydrocarbons from the system and to ensure safe working conditions for personnel conducting flare equipment inspection work. While the Main Flare was out of service for maintenance, flow was re-routed to the MP30 Flare (S-398).	No new prevention measures or corrective actions were identified. These activities were planned maintenance activities that will re-occur in the future.	N/A	N/A	Duration: 28:19 Flow: 2,948 Emissions (lb) SO2 – 344 CH4 – 692 NMHC –562	• Maintenance, Turnaround, Startup, Shutdown – Equipment Preparation for Maintenance & Working on Equipment (Section 4.2.1.1)	400-19 N
11/11/19	Unit 110 Hydrogen Plant Pressure Swing Adsorber Unplanned Shutdown	On November 11, 2019 the Rodeo Refinery was utilizing hydrogen from Unit 110, one of the two normal sources of Hydrogen. The Air Liquide third party Hydrogen Plant was undergoing a turnaround thus, was not providing a second source of hydrogen to the refinery. At approximately 1:09 PM there was an unplanned shutdown of a portion of the Unit 110 Hydrogen Plant. The Pressure Swing Adsorber (PSA) Hydrogen purification portion of Unit 110 shutdown. The loss of hydrogen led to the shutdown of the Unit 250 Diesel Hydrotreater. Flaring of unscrubbed gas occurred due to the shutdown of the PSA, the shutdown of Unit 250, and the related hydrogen imbalance that occurred as the PSA and Unit 250 restored normal operation following the shutdowns.	Valve PV-78C broken spring	1. Spring replaced 2. Evaluate and update the Preventative Maintenance (PM) frequency for PSA valves dependent on service, maintenance history, and manufacturer recommendations	1. COMPLETED 11/15/19 2. Target 11/20/20	Duration: 8:40 Flow: 1,965 Emissions (lb) SO2 – 140 CH4 – 498 NMHC –181	• Hydrogen Gas Balance (4.2.1.1) – unplanned Hydrogen plant shutdown • Upset/Malfunction (4.2.1.4) - Hydrogen plant PSA operational changes, switching from 10 bed to 8 bed operation • Upset/Malfunction (4.2.1.4) – failure of PSA valve	038-20 N
12/2/19	Fuel gas upset	A fuel gas upset occurred on December 2, 2019 that resulted in elevated sulfur concentrations in the refinery fuel gas ("RFG"). Due to the higher-than-typical sulfur concentrations in the RFG, RFG consumption at the Steam Power Plant (SPP) gas turbines was reduced to remain in compliance with federally enforceable permit conditions that limit SPP SO_2 mass emissions. The reduction in consumption of RFG at the SPP resulted in flaring of the scrubbed RFG.	Passivation agent used during pre-sulfiding caused elevated total sulfur in SPP fuel gas.	Identify alternative passivation agent for use during pre-sulfiding that will not result in the formation of mercaptans	COMPLETED 8/13/20	Duration: 17:10 Flow: 3,200 Emissions (lb) SO2 – 53 CH4 – 802 NMHC –1,865	• Upset/Malfunction (4.2.1.4) – fuel gas quality upsets • Maintenance, Turnaround, Startup, and Shutdown (4.2.1.1) – unit startup	082-20 N

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Attachment H

Date	Process or Equipment Item	Flaring Event Description	Root Cause Finding	Action Item(s)	Proposed Dates/Status	Duration, Flow & Emissions	Consistency with Flare Minimization Plan (12-12-406.3)	ESDR No. Recurrent Failure?
12/9/19	Unicracker Complex planned shutdown	The Unicracker (Unit 240) Complex underwent a turnaround during the 4th quarter of 2019. During the startup of Unit 240 there was a period of intermittent flaring of unscrubbed gas on December 9, 2019.	U240 high catalyst activity during catalyst conditioning.	Determine if another catalyst conditioning agent can be used that would allow for better control of light hydrocarbon production during future start-ups with fresh catalyst. Target 4/30/2020	COMPLETED 4/13/20	Duration: 7:55 (int) Flow: 248 Emissions (lb) SO2 – 712 CH4 – 51 NMHC – 162	• Maintenance, Turnaround, Startup, and Shutdown (4.2.1.1) – Unit startup and catalyst change	050-20 N
12/11/19	SRU Upset	At approximately 5:00 AM an upset began at the Sulfur Recovery Unit 235 (U235). Shortly after the Sulfur Recovery Unit 236 (U236) also began to show indications of upset conditions. In light of the upset conditions at U235 and U236 and resulting impacts to the Refinery fuel gas system, the Refinery Emergency Operating Procedure (REOP-10) "Unplanned Sulfur Plant Shutdown or Loss of DGA Circulation" was implemented. One of the elements of this procedure is to circulate the Flare Gas Recovery Compressors (FGRCs), which resulted in flaring of unscrubbed gas. Flaring occurred primarily from 7:52 AM to 11:40 AM. There were a few other brief (<10 minute individual) minor periods of flaring during the day.	Sponge oil pre-saturator vessel F-304 level indicator LI-004 malfunctioned during unit start up. Vessel hydrocarbons carried over to the DGA system.	1. Upon discovery of the failed level indicator, liquid level in F304 was manually lowered and the level indicator was corrected. 2. Schedule re-occuring preventative maintenance testing plan for LI-004. 3. Update Unit 240 Plant 3 start up procedure to require visual level verification of F-304 throughout start up activities. 4. Include weekly visual level verification using sight glass in unit operator rounds	1. COMPLETED 12/11/19 2. COMPLETED 3/7/20 3. COMPLETED 3/13/20 4. COMPLETED 3/13/20	Duration: 7:55 (int) Flow: 532 Emissions (lb) SO2 – 7,500 CH4 – 174 NMHC – 258	• Upset/Malfunction (4.2.1.4) – Failure of instrumentation, valve, pump, compressor, etc. to function as designed. • Upset/Malfunction (4.2.1.4) – Fuel quality upsets	054-20 N
3/5/20	3rd party power voltage sag.	On March 5, 2020 a voltage sag occurred in the third-party power supply. This resulted in flaring due to the loss of compressors and other major pieces of equipment. In addition, several process units were impacted by the voltage sag. The Unit 246 Hydrocracker shut down following the voltage sag. Flaring occurred after the voltage sag due to the unit and electrical impacts. Additional flaring occurred the following day due to a unit startup.	1. Third Party Power Supply Voltage Sag	Phillips 66 has engaged the third-party and has requested that its standard preventative maintenance practices be shared with Phillips 66. Phillips 66 is also in communication with the supplier on future capital projects for improving electrical supply reliability for lines that supply electricity to the refinery.	COMPLETED March 20, 2020 & on-going	Duration: 3:57 Flow: 208 Emissions (lb) SO2 – 715 CH4 – 32 NMHC – 143	• Upset/Malfunction (4.2.1.4) – Loss of a Utility	143-20 N
			2. Routing of Unit 246 D-803 H_2S Stripper overhead liquid to blowdown	Update procedure to keep U246 D-803 H2S Stripper overhead on-grade to Unit 240 Plant 3 at lower process rates before routing this stream to blowdown.	COMPLETED 6/9/20			

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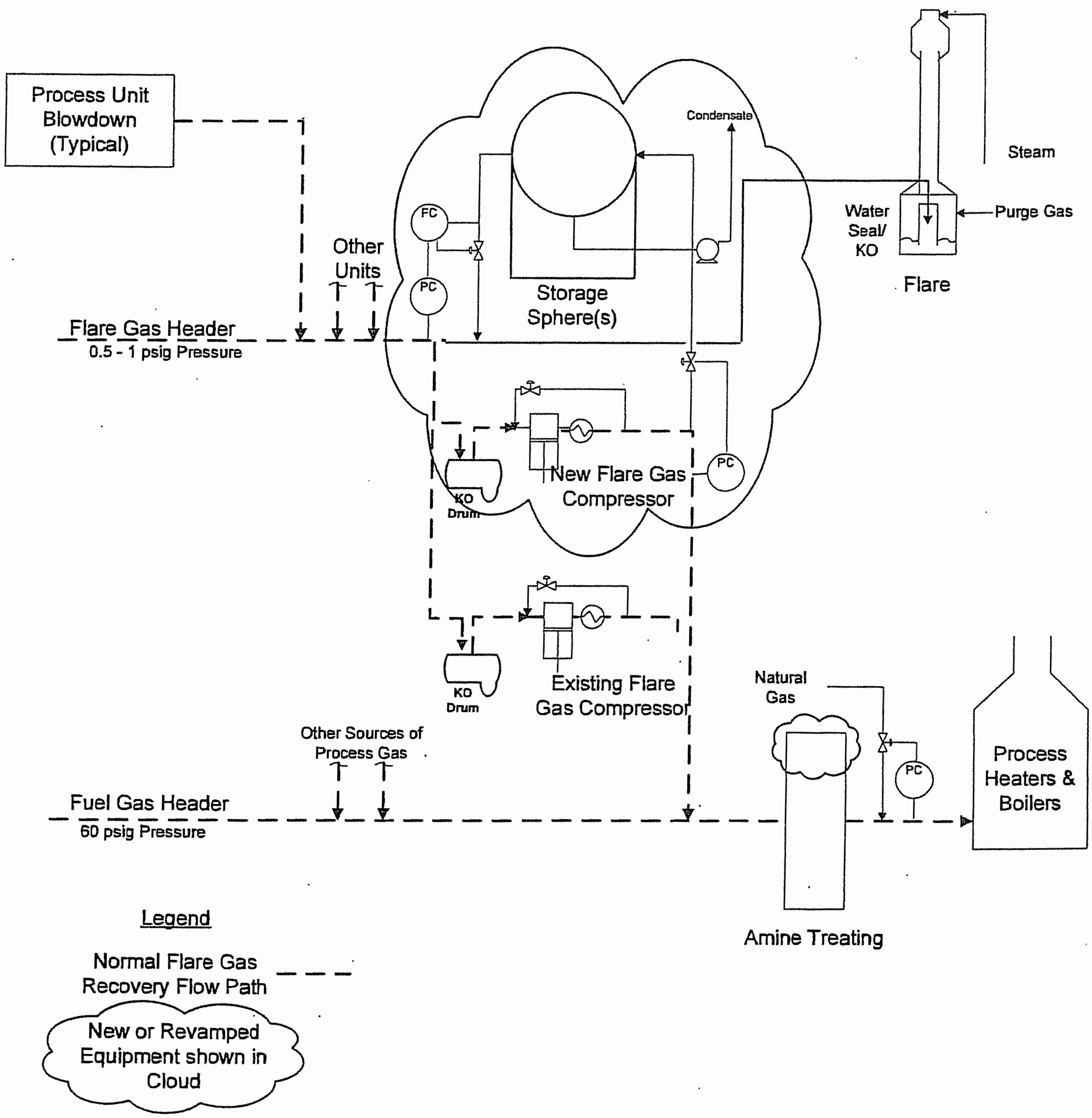
ATTACHMENT I

STORAGE, TREATMENT, & RECOVERY SCHEMATIC

Flare Gas Recovery With Storage Sphere



ATTACHMENT J

Pressure Relief Valves that can Vent to the Flare

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
COKER - #200 COKER	CVS NO RD	10180	6	GAS / VAPOR	T/6 SWSD T D-201 PRV PSV
COKER - #200 COKER	CVS NO RD	10182	6	GAS / VAPOR	T/6 SESD T D-202 PRV PSV
COKER - #200 COKER	CVS NO RD	10185	6	GAS / VAPOR	T/6 SWSD T D-203 PRV PSV
COKER - #200 COKER	CVS NO RD	10188	6	GAS / VAPOR	T/6 SESD T D-204 PRV PSV
COKER - #200 COKER	CVS NO RD	18720	3	GAS / VAPOR	7/6 6FT W T D-206 PRV PSV-990
COKER - #200 COKER	CVS NO RD	18723	3	GAS / VAPOR	7/6 8FT SW T D-206 PRV PSV-991
COKER - #200 COKER	CVS NO RD	18726	3	GAS / VAPOR	G/22 12FT S E E-213 PRV PSV-922
COKER - #200 COKER	CVS NO RD	18729	3	LIGHT LIQUID	1/9 SWSD E E-212B PRV PSV
COKER - #200 COKER	CVS NO RD	18735	3	LIGHT LIQUID	1/8 SESD E E-211 PRV PSV
COKER - #200 COKER	CVS NO RD	18750	6	GAS / VAPOR	T/8 MID T D-206 PRV PSV
COKER - #200 COKER	CVS NO RD	18868	3	GAS / VAPOR	1/4 8FT SE E E-511 PRV PSV-997
COKER - #200 COKER	CVS NO RD	21885	3	GAS / VAPOR	G/5 30FT N V F-502 ESD PRV PSV-104
COKER - #200 COKER	CVS NO RD	21904	4	GAS / VAPOR	G/23 ESD V F-103 PRV PSV-72
COKER - #200 COKER	CVS NO RD	21906	6	GAS / VAPOR	2/8 ABV E E-52 PRV
COKER - #200 COKER	CVS NO RD	21908	6	GAS / VAPOR	2/5 WSD E E-52 PRV PSV-130
COKER - #200 COKER	CVS NO RD	21912	3	LIGHT LIQUID	G/4 NSD P G-61 PRV PSV-120
COKER - #200 COKER	CVS NO RD	21916	6	GAS / VAPOR	1/9 15FT SW E E-211 PRV
COKER - #200 COKER	CVS NO RD	21964	6	GAS / VAPOR	T/4 NSD T D-505 PRV
COKER - #200 COKER	CVS NO RD	22044	0.5	GAS / VAPOR	1/10 TOP V F-501 PRV
COKER - #200 COKER	CVS NO RD	22366	1.5	GAS / VAPOR	1/7 WSD V D-561 PRV PSV-1869
COKER - #200 COKER	CVS NO RD	22429	1	GAS / VAPOR	1/4 CTR V F-540 PRV PSV-1865
COKER - #200 COKER	CVS NO RD	22549	1	GAS / VAPOR	G/6 22FT N V F-502 PRV PSV-116
COKER - #200 COKER	CVS NO RD	22787	2	GAS / VAPOR	T/4 WSD V D-504 PRV E
COKER - #200 COKER	CVS NO RD	22788	2	GAS / VAPOR	T/4 WSD V D-504 PRV W
COKER - #200 COKER	CVS NO RD	22935	2	LIGHT LIQUID	G/5 25FT NW E E-503B PRV PSV-106
COKER - #200 COKER	CVS NO RD	22954	4	GAS / VAPOR	G/4 20FT W H B-501 PRV PSV-122
COKER - #200 COKER	CVS NO RD	23047	1	LIGHT LIQUID	G/3 SSD P GM-54 PRV
COKER - #200 COKER	CVS NO RD	23069	6	GAS / VAPOR	T/2 TOP T D-103 SSD E E-111B
COKER - #200 COKER	CVS NO RD	23108	1	LIGHT LIQUID	1/2 NWSD E E-100 PRV PSV-79
COKER - #200 COKER	CVS NO RD	23402	1	GAS / VAPOR	1/3 WSD E E-212B
COKER - #200 COKER	CVS NO RD	23409	4	GAS / VAPOR	1/7 4FT SW E E-211
COKER - #200 COKER	CVS NO RD	23767	1.5	GAS / VAPOR	1/5 ESD FF E-62C PRV PSV-469
COKER - #200 COKER	CVS NO RD	23768	1.5	GAS / VAPOR	1/5 8FT NE FF E-62C PRV PSV-4040
COKER - #200 COKER	CVS NO RD	23769	0.75	GAS / VAPOR	1/5 8FT NE FF E-62C PRV PSV-401C

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
COKER - #200 COKER	CVS NO RD	23771	0.75	GAS / VAPOR	1/5 9FT NE FF E-62C PRV PSV-405C
COKER - #200 COKER	CVS NO RD	23776	1.5	GAS / VAPOR	1/5 8FT NE FF E-62B PRV PSV-404B
COKER - #200 COKER	CVS NO RD	23777	1	GAS / VAPOR	1/5 9FT NE FF E-62B PRV PSV-405B
COKER - #200 COKER	CVS NO RD	23779	1	GAS / VAPOR	1/5 10FT NE FF E-62B PRV PSV-401B
COKER - #200 COKER	CVS NO RD	23784	1.5	GAS / VAPOR	1/5 8FT NE FF E-62A PRV PSV-404A
COKER - #200 COKER	CVS NO RD	23785	1	GAS / VAPOR	1/5 9FT NE FF E-62A PRV PSV-405A
COKER - #200 COKER	CVS NO RD	23787	1	GAS / VAPOR	1/5 10FT NE FF E-62A PRV PSV-401A
COKER - #200 COKER	CVS NO RD	23840	0.75	GAS / VAPOR	G/13 ABV E E-207A PRV
COKER - #200 COKER	CVS NO RD	23843	0.75	LIGHT LIQUID	G/13 ABV E E-207C PRV
COKER - #200 COKER	CVS NO RD	23849	0.75	GAS / VAPOR	G/20 ABV E E-102A PRV PSV-713
COKER - #200 COKER	CVS NO RD	23851	0.75	GAS / VAPOR	G/20 ABV E E-102B PRV
COKER - #200 COKER	CVS NO RD	23853	0.75	GAS / VAPOR	G/20 ABV E E-103 PRV PSV-754
COKER - #200 COKER	CVS NO RD	23858	3	LIGHT LIQUID	G/22 ABV E E-210 BLD PRV PSV-993
COKER - #200 COKER	CVS NO RD	23871	0.75	GAS / VAPOR	G/15 10FT SE E E-102C PRV PSV-1168
COKER - #200 COKER	CVS NO RD	23872	0.75	GAS / VAPOR	G/18 10FT S E E-210 PRV PSV-925
COKER - #200 COKER	CVS NO RD	23874	3	GAS / VAPOR	G/15 SSD H B-5 PRV PSV-926
COKER - #200 COKER	CVS NO RD	23887	6	GAS / VAPOR	G/13 ESD V F-103 TOP
COKER - #200 COKER	CVS NO RD	23893	2	GAS / VAPOR	G/15 NSD V F-104 PRV PSV-979
COKER - #200 COKER	CVS NO RD	23963	2	GAS / VAPOR	G/18 SESD V F-14 PRV
COKER - #200 COKER	CVS NO RD	24064	3	GAS / VAPOR	1/7 10FT N E-237C CV FV-1560
COKER - #200 COKER	CVS NO RD	24070	2	LIGHT LIQUID	1/4 ESD E-240C CV FV-708
COKER - #200 COKER	CVS NO RD	24073	1.5	LIGHT LIQUID	1/3 SWSD E E-239 PRV PSV-978
COKER - #200 COKER	CVS NO RD	24142	4	GAS / VAPOR	T/2 MID V F-4 PRV PSV-12
COKER - #200 COKER	CVS NO RD	24161	3	GAS / VAPOR	T/6 NSD V F-204 PRV PSV-16
COKER - #200 COKER	CVS NO RD	24162	3	GAS / VAPOR	T/6 NSD V F-204 PRV PSV-17
COKER - #200 COKER	CVS NO RD	24233	2	GAS / VAPOR	G/12 18FT W E E-239 PRV
COKER - #200 COKER	CVS NO RD	24393	1	GAS / VAPOR	G/2 11FT NW H B-201 PRV PC-604
COKER - #200 COKER	CVS NO RD	24499	0.75	LIGHT LIQUID	G/10 SSD E E-113 PRV
COKER - #200 COKER	CVS NO RD	24502	1	GAS / VAPOR	1/4 WSD FF E-219 PRV
COKER - #200 COKER	CVS NO RD	24649	6	GAS / VAPOR	T/6 SWSD V D-101 PRV PSV-767
COKER - #200 COKER	CVS NO RD	24650	6	GAS / VAPOR	T/6 MID V D-101 PRV PSV-14
COKER - #200 COKER	CVS NO RD	24720	6	GAS / VAPOR	1/8 ESD V F-101 PRV
COKER - #200 COKER	CVS NO RD	24923	2	GAS / VAPOR	3/7 10FT NE E E-201 PRV PSV-745
COKER - #200 COKER	CVS NO RD	25040	6	GAS / VAPOR	T/5 ESD T D-205 PRV PSV-742

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
COKER - #200 COKER	CVS NO RD	26209	6	GAS / VAPOR	2/4 35FT SE H B-202 PRV PSV-854
COKER - #200 COKER	CVS NO RD	26214	6	GAS / VAPOR	2/4 20FT SE H B-202 PRV PSV-856
COKER - #200 COKER	CVS NO RD	26219	1	GAS / VAPOR	2/5 25FT SE H B-202 PRV PSV-859
COKER - #200 COKER	CVS NO RD	26317	0.25	LIGHT LIQUID	G/1 15FT S P G-215 PRV
COKER - #200 COKER	CVS NO RD	26453	8	GAS / VAPOR	T/5 NSD T D-206 PRV PSV-900 S
COKER - #200 COKER	CVS NO RD	26455	6	GAS / VAPOR	T/5 NSD T D-206 PRV PSV-901
COKER - #200 COKER	CVS NO RD	26456	8	GAS / VAPOR	T/5 NSD T D-206 PRV PSV-902 N
COKER - #200 COKER	CVS NO RD	26476	3	GAS / VAPOR	2/4 45FT NE T D-204 PRV
COKER - #200 COKER	CVS NO RD	26726	6	GAS / VAPOR	T/6 SWSD T D-201 PRV PSV-867
COKER - #200 COKER	CVS NO RD	26750	8	GAS / VAPOR	T/6 SESD T D-202 PRV PSV-873
COKER - #200 COKER	CVS NO RD	26755	6	GAS / VAPOR	T/6 SWSD T D-203 PRV PSV-757
COKER - #200 COKER	CVS NO RD	26776	6	GAS / VAPOR	T/6 SESD T D-204 PRV PSV-881
COKER - #200 COKER	CVS NO RD	31587	3	GAS / VAPOR	1/7 SWSD E E-108 PRV PSV
COKER - #200 COKER	CVS NO RD	31591	2	LIGHT LIQUID	1/5 ESD E E-239 PRV PSV-994
COKER - #200 COKER	CVS NO RD	32131	3	GAS / VAPOR	1/5 SSD T D-101 PRV PSV-982
COKER - #200 COKER	CVS NO RD	32133	3	GAS / VAPOR	1/9 NSD E E-211 PRV
COKER - #200 COKER	CVS NO RD	32203	3	GAS / VAPOR	G/15 100FT SE FLR 19C-1
COKER - #200 COKER	CVS NO RD	32304	1	LIGHT LIQUID	G/3 65FT SE CNR J ST. & ROAD 6 PRV PSV-84
COKER - #200 COKER	CVS NO RD	36368	1	GAS / VAPOR	G/5 5FT E H B-201 PRV PSV-61
COKER - #200 COKER	CVS NO RD	36373	2	GAS / VAPOR	T/8 NESD V F-224 PRV
COKER - #200 COKER	CVS NO RD	50214	6	GAS / VAPOR	G/7 10FT NW C G-503 PRV PSV-120
COKER - #200 COKER	CVS NO RD	50215	6	GAS / VAPOR	G/7 8FT W C G-503 PRV PSV-131
COKER - #200 COKER	CVS NO RD	80018	2	GAS / VAPOR	T/4 WSD V D-503 PRV PSV 102
COKER - #200 COKER	CVS NO RD	83064	4	GAS / VAPOR	1/4 NSD E E-237C ESD PRV PSV-995
COKER - #200 COKER	CVS NO RD	83742	0.75	LIGHT LIQUID	3/5 ESD E E-201 PRV PSV-707
COKER - #215 GAS FRACT.	CVS NO RD	3265	3	GAS / VAPOR	3/6 8FT NE E E-702A PRV PSV-862 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3267	6	GAS / VAPOR	3/5 8FT N E E-702A PRV PSV-749 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3270	1.5	GAS / VAPOR	2/4 7FT NE E E-702A PRV PSV-717 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3271	1.5	GAS / VAPOR	2/4 8FT NW E E-702A PRV PSV-712 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3277	6	GAS / VAPOR	2/4 6FT W E E-702B PRV PSV-792
COKER - #215 GAS FRACT.	CVS NO RD	3485	1.5	GAS / VAPOR	T/5 ESD V F-101 PRV 215 PSV-20 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3581	3	GAS / VAPOR	T/6 TOP V D-101 PRV 215 PSV-6 PRV
COKER - #215 GAS FRACT.	CVS NO RD	3818	2	GAS / VAPOR	1/0 TOP TK F-111 PRV 1-D-A
COKER - #215 GAS FRACT.	CVS NO RD	3823	20	GAS / VAPOR	1/0 TOP TK F-111 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
COKER - #215 GAS FRACT.	CVS NO RD	4081	1.5	GAS / VAPOR	2/3 5FT NE V F-122 PRV PSV-847 PRV
COKER - #215 GAS FRACT.	CVS NO RD	4084	1.5	GAS / VAPOR	2/3 5FT N V F-122 PRV PSV-846 PRV
COKER - #215 GAS FRACT.	CVS NO RD	4085	1.5	GAS / VAPOR	2/3 5FT NW V F-122 PRV PSV-845 PRV
COKER - #215 GAS FRACT.	CVS NO RD	4163	2	LIGHT LIQUID	G/22 8FT NW V F-126 PRV
COKER - #215 GAS FRACT.	CVS NO RD	4165	2	LIGHT LIQUID	G/22 12FT NW V F-126 PRV
COKER - #215 GAS FRACT.	CVS NO RD	52230	2	LIGHT LIQUID	G/5 NSD P G-103A PRV PSV-30
COKER - #215 GAS FRACT.	CVS NO RD	52232	2	LIGHT LIQUID	G/4 NSD P G-103 PRV PSV-29
COKER - #215 GAS FRACT.	CVS NO RD	52503	4	GAS / VAPOR	2/2 SSD V F-4 PRV PSV-18
COKER - #215 GAS FRACT.	CVS NO RD	52504	6	GAS / VAPOR	T/5 ABV V D-4 PRV 215 PSV-1 PRV
COKER - #215 GAS FRACT.	CVS NO RD	52506	1	LIGHT LIQUID	G/8 20FT SE V F-1 PRV PSV-45
COKER - #215 GAS FRACT.	CVS NO RD	80913	1.5	GAS / VAPOR	2/4 8FT NW E E-702A PRV PSV-732 PRV
COKER - #215 GAS FRACT.	CVS NO RD	80914	1.5	GAS / VAPOR	4/4 ABV V F-702A PRV PSV-731 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	31963	6	GAS / VAPOR	G/11 5FT E V F-601 PRV PSV-11
COKER - #233 FUEL GAS CENTER	CVS NO RD	6555	6	GAS / VAPOR	1/3 ABV V F-603 PRV PSV-9 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	6715	4	GAS / VAPOR	G/10 ABV E E-601 PRV PV-601 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	6754	3	GAS / VAPOR	1/6 ESD V F-605 PRV PSV-10 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	7323	2	GAS / VAPOR	G/15 TOP V F-604 PRV PSV-5 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	7347	6	GAS / VAPOR	1/10 ABV V F-601 PRV PV-1 PRV
COKER - #233 FUEL GAS CENTER	CVS NO RD	7378	6	GAS / VAPOR	1/9 ABV V F-602 PRV PV-2 PRV
COKER - #267 CRUDE	CVS NO RD	33369	3	GAS / VAPOR	1/4 WSD E E-612 PRV PSV-1514
COKER - #267 CRUDE	CVS NO RD	33372	3	GAS / VAPOR	1/5 WSD E E-612 PRV PSV-1518
COKER - #267 CRUDE	CVS NO RD	33435	4	GAS / VAPOR	G/25 15FT NW P G-601A PRV PSV-1521
COKER - #267 CRUDE	CVS NO RD	33436	4	GAS / VAPOR	G/25 16FT NW P G-601A PRV PSV
COKER - #267 CRUDE	CVS NO RD	33837	1.5	GAS / VAPOR	1/5 5FT S T D-601 PRV PSV-1751
COKER - #267 CRUDE	CVS NO RD	34284	2	GAS / VAPOR	2/5 7FT SE E E-603A PRV PSV-1685
COKER - #267 CRUDE	CVS NO RD	34286	3	GAS / VAPOR	2/5 8FT SE E E-603 A PRV PSV-1634
COKER - #267 CRUDE	CVS NO RD	34289	4	GAS / VAPOR	2/5 9FT SE E E-603 A PRV PSV-1626
COKER - #267 CRUDE	CVS NO RD	34307	0.75	LIGHT LIQUID	2/6 ESD E E-602B PRV PSV-1507
COKER - #267 CRUDE	CVS NO RD	34319	0.75	LIGHT LIQUID	2/6 ESD E E-602A PRV PSV-1506
COKER - #267 CRUDE	CVS NO RD	34353	4	GAS / VAPOR	3/12 SSD E E-625 PRV
COKER - #267 CRUDE	CVS NO RD	34374	8	GAS / VAPOR	3/6 13FT E E E-631 PRV PSV-1619A
COKER - #267 CRUDE	CVS NO RD	34376	8	GAS / VAPOR	3/6 12FT E E E-631 PRV PSV-1619B
COKER - #267 CRUDE	CVS NO RD	34386	0.5	LIGHT LIQUID	G/4 4FT SE D F-616 PRV PSV-1532
COKER - #267 CRUDE	CVS NO RD	52501	0.75	LIGHT LIQUID	G/4 4FT SE D F-616 PRV PSV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
COKER - #267 CRUDE	CVS NO RD	52539	3	GAS / VAPOR	1/5 WSD E E-612 PRV PSV-1803
COKER - #267 CRUDE	CVS NO RD	52553	3	GAS / VAPOR	1/5 WSD E E-612 PRV PSV-1802
COKER - #267 CRUDE	CVS NO RD	53937	3	LIGHT LIQUID	1/3 NSD FF E-608 PRV PSV-1703
COKER - #267 CRUDE	CVS NO RD	53938	3	LIGHT LIQUID	1/5 NSD FF E-608 ESD PRV PSV-1707
COKER - #267 CRUDE	CVS NO RD	53939	3	LIGHT LIQUID	1/3 NESD FF E-608 PRV PSV-1712
COKER - #267 CRUDE	CVS NO RD	80557	0.5	LIGHT LIQUID	G/2 4FT NW E E-614A SWSD CHEM TOTE
COKER - #267 CRUDE	CVS NO RD	81139	3	LIGHT LIQUID	1/3 NSD FF E-608 PRV PSV-1698
EAST BULK - #100 WASTE WATER	CVS NO RD	10255	1	LIGHT LIQUID	G/6 NESD P G-10 PRV-PSV-4 PRV
EAST BULK - #100 WASTE WATER	CVS NO RD	10268	1	LIGHT LIQUID	G/4 NSD P G-8 PRV PSV-5
EAST BULK - #100 WASTE WATER	CVS NO RD	10270	1	LIGHT LIQUID	G/4 SSD P G-7 PRV PSV-6
EAST BULK - #100 WASTE WATER	CVS NO RD	10285	1	LIGHT LIQUID	G/6 SSD P G-9 PRV PSV-4
EAST BULK - #100 WASTE WATER	CVS NO RD	10322	3	LIGHT LIQUID	G/3 SSD P G-167 PRV PSV-U-355
EAST BULK - #100 WASTE WATER	CVS NO RD	10332	3	LIGHT LIQUID	G/4 SSD P G-267 PRV PSV-955
EAST BULK - #100 WASTE WATER	CVS NO RD	10543	1	LIGHT LIQUID	G/5 NWSD TK TK-501 PRV
EAST BULK - #100 WASTE WATER	CVS NO RD	10654	1	GAS / VAPOR	G/7 4FT S C E-235B PRV PSV-71
EAST BULK - #100 WASTE WATER	CVS NO RD	10677	1	GAS / VAPOR	G/8 NESD V F-207B
EAST BULK - #100 WASTE WATER	CVS NO RD	10703	1	GAS / VAPOR	G/7 4FT S C E-235A PRV PSV-1378
EAST BULK - #100 WASTE WATER	CVS NO RD	10728	1	GAS / VAPOR	G/8 NESD V F-207A PRV
EAST BULK - #100 WASTE WATER	CVS NO RD	10786	3	GAS / VAPOR	1/4 TOP V F-206 PRV PSV-900
EAST BULK - #100 WASTE WATER	CVS NO RD	10849	6	GAS / VAPOR	1/2 WSD V F-216 PRV PSV-922
EAST BULK - #100 WASTE WATER	CVS NO RD	10857	1	LIGHT LIQUID	G/4 ESD P GM-219A PRV PSV-930
EAST BULK - #100 WASTE WATER	CVS NO RD	10864	1	LIGHT LIQUID	G/4 WSD P GM-219B PRV PSV-931
EAST BULK - #100 WASTE WATER	CVS NO RD	10915	4	GAS / VAPOR	1/2 TOP V F-218 PRV PSV-1145
EAST BULK - #100 WASTE WATER	CVS NO RD	10938	10	GAS / VAPOR	1/4 19FT W P G-210 PRV PSV-848
EAST BULK - #100 WASTE WATER	CVS NO RD	11023	8	GAS / VAPOR	1/4 8FT N P G-234C PRV PSV-847
EAST BULK - #100 WASTE WATER	CVS NO RD	11139	1	LIGHT LIQUID	G/3 111FT W P G-231 PRV PSV-237
EAST BULK - #100 WASTE WATER	CVS NO RD	11166	0.75	LIGHT LIQUID	G/2 12FT SW P G-231
EAST BULK - #100 WASTE WATER	CVS NO RD	11167	1	LIGHT LIQUID	G/2 12FT SW P G-231
EAST BULK - #100 WASTE WATER	CVS NO RD	11178	1	LIGHT LIQUID	G/1 5FT SW P G-231
EAST BULK - #100 WASTE WATER	CVS NO RD	11186	0.75	LIGHT LIQUID	G/3 WSD P G-231
EAST BULK - #100 WASTE WATER	CVS NO RD	11208	1	LIGHT LIQUID	G/3 7FT E TK TK-193 N
EAST BULK - #100 WASTE WATER	CVS NO RD	11209	1	LIGHT LIQUID	G/3 7FT E TK TK-193 MID
EAST BULK - #100 WASTE WATER	CVS NO RD	11212	1	LIGHT LIQUID	G/3 7FT E TK TK-193 S
EAST BULK - #100 WASTE WATER	CVS NO RD	11295	0.75	LIGHT LIQUID	G/5 NESD TK TK-130 PRV PSV-1439

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #100 WASTE WATER	CVS NO RD	11426	1.5	GAS / VAPOR	G/5 WSD TK TK-235 PRV PCV-235
EAST BULK - #100 WASTE WATER	CVS NO RD	11432	2	GAS / VAPOR	G/8 5FT NW TK TK-235 PRV PSV-132
EAST BULK - #100 WASTE WATER	CVS NO RD	11458	2	LIGHT LIQUID	G/8 NESD TK TK-236 PRV PSV-133
EAST BULK - #100 WASTE WATER	CVS NO RD	11461	1.5	LIGHT LIQUID	G/5 ESD TK TK-236 PRV PCV-236
EAST BULK - #100 WASTE WATER	CVS NO RD	11569	0.75	LIGHT LIQUID	G/3 6FT W TK TK-194 PRV PSV-183
EAST BULK - #100 WASTE WATER	CVS NO RD	11570	0.75	LIGHT LIQUID	G/3 6FT W TK TK-194 PRV PSV-151
EAST BULK - #100 WASTE WATER	CVS NO RD	11571	0.75	LIGHT LIQUID	G/3 6FT W TK TK-194 PRV PSV-150
EAST BULK - #100 WASTE WATER	CVS NO RD	2874	1	LIGHT LIQUID	G/5 SWSD TK TK-502 PRV PSV-1441
EAST BULK - #40 RAW MAT.	CVS NO RD	21896	1	LIGHT LIQUID	G/6 SESD TK TK-200 PRV PSV-59
EAST BULK - #40 RAW MAT.	CVS NO RD	27177	0.75	LIGHT LIQUID	G/4 9FT SE P G-6 PRV PSV-73
EAST BULK - #40 RAW MAT.	CVS NO RD	27191	0.75	LIGHT LIQUID	G/4 4FT W TK TK-150 PRV PSV-20
EAST BULK - #40 RAW MAT.	CVS NO RD	27199	0.75	LIGHT LIQUID	G/4 6FT W TK TK-150 PRV PSV-21
EAST BULK - #40 RAW MAT.	CVS NO RD	27354	1	LIGHT LIQUID	G/8 25FT SW BLDG 40 CNTRL ROOM ABV CV FV-113
EAST BULK - #40 RAW MAT.	CVS NO RD	27470	1	LIGHT LIQUID	G/5 46FT NW BLDG 40 CNTRL ROOM PRV PSV-18
EAST BULK - #40 RAW MAT.	CVS NO RD	27478	8	LIGHT LIQUID	G/7 50FT NW BLDG 40 CNTRL ROOM PRV PSV-2
EAST BULK - #40 RAW MAT.	CVS NO RD	27483	8	LIGHT LIQUID	G/6 56FT NW BLDG 40 CNTRL ROOM PRV PSV-1
EAST BULK - #40 RAW MAT.	CVS NO RD	27611	1	LIGHT LIQUID	G/6 18FT SE P G-3 PRV PSV-63
EAST BULK - #40 RAW MAT.	CVS NO RD	27641	0.75	LIGHT LIQUID	G/4 4FT E P G-3 PRV PSV-31
EAST BULK - #40 RAW MAT.	CVS NO RD	27686	0.75	LIGHT LIQUID	G/6 4FT N P G-3A PRV PSV-30
EAST BULK - #40 RAW MAT.	CVS NO RD	27722	0.75	LIGHT LIQUID	G/4 7FT E P G-4 PRV PSV-18
EAST BULK - #40 RAW MAT.	CVS NO RD	27795	0.75	LIGHT LIQUID	G/8 7FT N P G-7 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	27817	0.75	LIGHT LIQUID	G/4 16FT NE P G-7 PRV PSV-55
EAST BULK - #40 RAW MAT.	CVS NO RD	27887	0.75	LIGHT LIQUID	G/5 6FT E P G-6A PRV PSV-57
EAST BULK - #40 RAW MAT.	CVS NO RD	27959	1	LIGHT LIQUID	G/4 8FT W TK TK-159 PRV PSV-11
EAST BULK - #40 RAW MAT.	CVS NO RD	27966	2	LIGHT LIQUID	G/4 8FT W TK TK-159 PRV PSV-12
EAST BULK - #40 RAW MAT.	CVS NO RD	27971	1	LIGHT LIQUID	G/3 WSD TK TK-159 PRV PSV-13
EAST BULK - #40 RAW MAT.	CVS NO RD	27992	0.75	LIGHT LIQUID	G/4 SESD TK TK-157 PRV PSV-6
EAST BULK - #40 RAW MAT.	CVS NO RD	27994	0.75	LIGHT LIQUID	G/3 SESD TK TK-157 PRV PSV-5
EAST BULK - #40 RAW MAT.	CVS NO RD	28003	0.75	LIGHT LIQUID	G/4 8FT S TK TK-157 PRV PSV-4
EAST BULK - #40 RAW MAT.	CVS NO RD	28010	0.75	LIGHT LIQUID	G/4 7FT S TK TK-157 PRV PSV-3
EAST BULK - #40 RAW MAT.	CVS NO RD	28018	0.75	LIGHT LIQUID	G/5 SESD TK TK-158 PRV PSV-9
EAST BULK - #40 RAW MAT.	CVS NO RD	28031	0.75	LIGHT LIQUID	G/4 8FT S TK TK-158 PRV PSV-8
EAST BULK - #40 RAW MAT.	CVS NO RD	28038	0.75	LIGHT LIQUID	G/4 7FT S TK TK-158 PRV PSV-7
EAST BULK - #40 RAW MAT.	CVS NO RD	28043	0.75	LIGHT LIQUID	G/6 100FT E TK TK-156 TOP PIG LAUNCHER

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #40 RAW MAT.	CVS NO RD	28063	0.75	LIGHT LIQUID	G/4 6FT E TK TK-108 PRV PSV-705
EAST BULK - #40 RAW MAT.	CVS NO RD	28068	0.75	LIGHT LIQUID	G/3 6FT E TK TK-108 PRV PSV-706
EAST BULK - #40 RAW MAT.	CVS NO RD	28078	0.75	LIGHT LIQUID	G/4 SESD TK TK-108 PRV PSV-707
EAST BULK - #40 RAW MAT.	CVS NO RD	28084	0.75	LIGHT LIQUID	G/4 6FT E TK TK-107 PRV PSV-689
EAST BULK - #40 RAW MAT.	CVS NO RD	28088	0.75	LIGHT LIQUID	G/5 6FT E TK TK-107 PRV PSV-688
EAST BULK - #40 RAW MAT.	CVS NO RD	28101	0.75	LIGHT LIQUID	G/5 NESD TK TK-107 PRV PSV-696
EAST BULK - #40 RAW MAT.	CVS NO RD	28114	0.75	LIGHT LIQUID	G/3 SESD TK TK-156 PRV PSV-766
EAST BULK - #40 RAW MAT.	CVS NO RD	28126	0.75	LIGHT LIQUID	G/4 6FT E TK TK-156 PRV PSV-43
EAST BULK - #40 RAW MAT.	CVS NO RD	28130	0.75	LIGHT LIQUID	G/4 6FT E TK TK-156 PRV PSV-45
EAST BULK - #40 RAW MAT.	CVS NO RD	28139	0.75	LIGHT LIQUID	G/3 NESD TK TK-180 PRV PSV-551
EAST BULK - #40 RAW MAT.	CVS NO RD	28140	0.75	LIGHT LIQUID	G/4 NESD TK TK-180 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	28154	0.75	LIGHT LIQUID	G/4 8FT N TK TK-180 PRV PSV-55A
EAST BULK - #40 RAW MAT.	CVS NO RD	28156	0.75	LIGHT LIQUID	G/4 8FT N TK TK-180 PRV PSV-556
EAST BULK - #40 RAW MAT.	CVS NO RD	28168	0.75	LIGHT LIQUID	G/3 NESD TK TK-155 PRV PSV-238
EAST BULK - #40 RAW MAT.	CVS NO RD	28180	0.75	LIGHT LIQUID	G/4 7FT N TK TK-155 PRV PSV-42
EAST BULK - #40 RAW MAT.	CVS NO RD	28183	0.75	LIGHT LIQUID	G/4 15FT N TK TK-155 PRV PSV-38
EAST BULK - #40 RAW MAT.	CVS NO RD	28200	0.75	LIGHT LIQUID	G/3 NWSD TK TK-150 PRV PSV-71
EAST BULK - #40 RAW MAT.	CVS NO RD	28230	2	GAS / VAPOR	G/3 47FT SW TK TK-202
EAST BULK - #40 RAW MAT.	CVS NO RD	28250	1	LIGHT LIQUID	G/5 8FTW TK TK-257 PRV PSV-132
EAST BULK - #40 RAW MAT.	CVS NO RD	28292	0.75	LIGHT LIQUID	G/3 NWSD TK TK-257 PRV PSV-133
EAST BULK - #40 RAW MAT.	CVS NO RD	28395	1	LIGHT LIQUID	G/3 5FT W TK TK-204 PRV PSV-647
EAST BULK - #40 RAW MAT.	CVS NO RD	28479	0.75	GAS / VAPOR	T/4 SWSD TK TK-269 PRV PSV-269
EAST BULK - #40 RAW MAT.	CVS NO RD	28490	2	GAS / VAPOR	G/5 NESD V F-600 PRV PSV-0075
EAST BULK - #40 RAW MAT.	CVS NO RD	28526	1	LIGHT LIQUID	G/3 12FT SW TK TK-271 PRV PSV-772
EAST BULK - #40 RAW MAT.	CVS NO RD	28531	1	LIGHT LIQUID	G/3 13FT SW TK TK-271 PRV PSV-770
EAST BULK - #40 RAW MAT.	CVS NO RD	28608	1	LIGHT LIQUID	G/4 35FT SW TK TK-285 PRV PSV-769
EAST BULK - #40 RAW MAT.	CVS NO RD	28611	1	LIGHT LIQUID	G/2 35FT SW TK TK-285 PRV PSV-767
EAST BULK - #40 RAW MAT.	CVS NO RD	28791	1	LIGHT LIQUID	G/3 5FT SW TK TK-298 PRV PSV-374
EAST BULK - #40 RAW MAT.	CVS NO RD	28793	1	LIGHT LIQUID	G/3 5FT SW TK TK-298 PRV PSV-375
EAST BULK - #40 RAW MAT.	CVS NO RD	28806	1	LIGHT LIQUID	G/4 WSD TK TK-298 PRV PSV-76
EAST BULK - #40 RAW MAT.	CVS NO RD	28821	1	LIGHT LIQUID	G/3 5FT SW TK TK-296 PRV PSV-383
EAST BULK - #40 RAW MAT.	CVS NO RD	28836	1	LIGHT LIQUID	G/5 WSD TK TK-296 PRV PSV-72
EAST BULK - #40 RAW MAT.	CVS NO RD	28849	1	LIGHT LIQUID	G/2 5FT SW TK TK-295 PRV PSV-380
EAST BULK - #40 RAW MAT.	CVS NO RD	28850	1	LIGHT LIQUID	G/3 6FT SW TK TK-295 PRV PSV-366

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #40 RAW MAT.	CVS NO RD	29029	0.75	LIGHT LIQUID	G/3 20FT NE CNR M ST & ROAD 5 PRV PSV-1548
EAST BULK - #40 RAW MAT.	CVS NO RD	29032	0.75	LIGHT LIQUID	G/3 20FT NE CNR M ST & ROAD 5 PRV PSV-894
EAST BULK - #40 RAW MAT.	CVS NO RD	29055	1	LIGHT LIQUID	G/2 38FT SW V F-809 PRV PSV-7
EAST BULK - #40 RAW MAT.	CVS NO RD	29059	0.75	LIGHT LIQUID	G/2 36FT SW V F-809 PRV PSV-5
EAST BULK - #40 RAW MAT.	CVS NO RD	29107	0.75	GAS / VAPOR	G/4 48FT W V F-809 PRV PSV-62
EAST BULK - #40 RAW MAT.	CVS NO RD	29112	0.75	GAS / VAPOR	G/4 48FT E V F-809 PRV PSV-383
EAST BULK - #40 RAW MAT.	CVS NO RD	29116	0.75	LIGHT LIQUID	G/4 48FT E V F-809 PRV PSV-379
EAST BULK - #40 RAW MAT.	CVS NO RD	29119	0.75	LIGHT LIQUID	G/4 48FT E V F-809 PRV PSV-358
EAST BULK - #40 RAW MAT.	CVS NO RD	29122	0.75	LIGHT LIQUID	G/4 48FT E V F-809 PRV PSV-359
EAST BULK - #40 RAW MAT.	CVS NO RD	29124	0.75	GAS / VAPOR	G/4 48FT E V F-809 PRV PSV-180
EAST BULK - #40 RAW MAT.	CVS NO RD	29127	0.75	LIGHT LIQUID	G/4 48FT E V F-809 PRV PSV-387
EAST BULK - #40 RAW MAT.	CVS NO RD	29185	0.75	LIGHT LIQUID	G/8 4FT N CNR O ST & ROAD 7 PRV PSV-388
EAST BULK - #40 RAW MAT.	CVS NO RD	29187	0.75	LIGHT LIQUID	G/2 NSD CNR O ST & ROAD 7 PRV PSV-591
EAST BULK - #40 RAW MAT.	CVS NO RD	29229	0.75	LIGHT LIQUID	G/5 60FT NE CNR N ST & ROAD 7 PRV PSV-44
EAST BULK - #40 RAW MAT.	CVS NO RD	29275	0.75	LIGHT LIQUID	G/6 25FT S CNR M ST. & ROAD 7 PRV PSV-30
EAST BULK - #40 RAW MAT.	CVS NO RD	29294	0.75	LIGHT LIQUID	G/3 40FT S CNR M ST. & ROAD 7 PRV PSV-702
EAST BULK - #40 RAW MAT.	CVS NO RD	29300	1	LIGHT LIQUID	G/3 42FT S CNR M ST. & ROAD 7 PRV PSV-436
EAST BULK - #40 RAW MAT.	CVS NO RD	29329	0.75	LIGHT LIQUID	G/4 15FT NE CNR I ST & ROAD 7 PRV PSV-121
EAST BULK - #40 RAW MAT.	CVS NO RD	29330	0.75	LIGHT LIQUID	G/4 16FT NE CNR I ST. & ROAD 7 PRV PSV-547
EAST BULK - #40 RAW MAT.	CVS NO RD	29347	0.75	LIGHT LIQUID	1/2 6FT NE P CP-827 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	29411	0.75	LIGHT LIQUID	G/3 50FT SW CNR M ST & ROAD 7 PRV PSV-384
EAST BULK - #40 RAW MAT.	CVS NO RD	29418	0.75	LIGHT LIQUID	G/2 35FT SW CNR M ST. & ROAD 7 PRV PSV-365
EAST BULK - #40 RAW MAT.	CVS NO RD	29420	0.75	LIGHT LIQUID	G/3 45FT SW CNR M ST. & ROAD 7 PRV PSV-363
EAST BULK - #40 RAW MAT.	CVS NO RD	29430	0.75	LIGHT LIQUID	G/4 50FT SW CNR M ST. & ROAD 7 PRV PSV-364
EAST BULK - #40 RAW MAT.	CVS NO RD	29439	1	LIGHT LIQUID	G/5 55FT S CNR M ST & ROAD 7 PRV PSV-411
EAST BULK - #40 RAW MAT.	CVS NO RD	29442	1	LIGHT LIQUID	G/5 54FT S CNR M ST & ROAD 7 PRV PSV-410
EAST BULK - #40 RAW MAT.	CVS NO RD	29482	0.75	LIGHT LIQUID	G/2 28FT SW CNR M ST & ROAD 6 PRV PSV-461
EAST BULK - #40 RAW MAT.	CVS NO RD	29488	1	LIGHT LIQUID	G/2 25FT SW CNR M ST & ROAD 6 PRV PSV-460
EAST BULK - #40 RAW MAT.	CVS NO RD	29546	0.75	LIGHT LIQUID	G/2 20FT SW P CP-1253 PRV PSV-51
EAST BULK - #40 RAW MAT.	CVS NO RD	29575	0.75	LIGHT LIQUID	G/3 30FT W CNR J ST & ROAD 7 PRV PSV-812
EAST BULK - #40 RAW MAT.	CVS NO RD	29577	0.75	LIGHT LIQUID	G/4 40FT W CNR J ST & ROAD 7 PRV PSV-37
EAST BULK - #40 RAW MAT.	CVS NO RD	29586	0.75	LIGHT LIQUID	G/2 38FT W CNR J ST. & ROAD 7 PRV PSV-176
EAST BULK - #40 RAW MAT.	CVS NO RD	29589	0.75	LIGHT LIQUID	G/2 38FT W CNR J ST. & ROAD 7 PRV PSV-402
EAST BULK - #40 RAW MAT.	CVS NO RD	29591	0.75	LIGHT LIQUID	G/2 38FT W CNR J ST. & ROAD 7 PRV PSV-398

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #40 RAW MAT.	CVS NO RD	29592	0.75	LIGHT LIQUID	G/2 38FT W CNR J ST. & ROAD 7 PRV PSV-200
EAST BULK - #40 RAW MAT.	CVS NO RD	29595	0.75	LIGHT LIQUID	G/4 39FT W CNR J ST & ROAD 7 PRV PSV-1546
EAST BULK - #40 RAW MAT.	CVS NO RD	29621	0.75	LIGHT LIQUID	1/6 18FT SE P CP-931 PRV PSV-594
EAST BULK - #40 RAW MAT.	CVS NO RD	29635	0.75	LIGHT LIQUID	G/5 10FT S P CP-931 PRV PSV-212
EAST BULK - #40 RAW MAT.	CVS NO RD	29658	0.75	LIGHT LIQUID	1/7 15FT S P CP-931 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	29663	0.75	LIGHT LIQUID	G/7 13FT SE P CP-389 PRV PSV-40
EAST BULK - #40 RAW MAT.	CVS NO RD	29666	0.75	LIGHT LIQUID	G/5 10FT SE P G-106 PRV PSV-228
EAST BULK - #40 RAW MAT.	CVS NO RD	29680	0.75	LIGHT LIQUID	1/7 16FT SW P CP-389 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	29682	0.75	LIGHT LIQUID	G/2 18FT SW P CP-389 PRV PSV-235
EAST BULK - #40 RAW MAT.	CVS NO RD	29684	0.75	LIGHT LIQUID	G/2 14FT SW P CP-389 PRV PSV-301
EAST BULK - #40 RAW MAT.	CVS NO RD	29687	0.75	LIGHT LIQUID	G/7 12FT SW P G-106 PRV PSV-197
EAST BULK - #40 RAW MAT.	CVS NO RD	29688	0.75	LIGHT LIQUID	G/2 12FT SW P G-106 PRV PSV-244
EAST BULK - #40 RAW MAT.	CVS NO RD	29704	0.75	LIGHT LIQUID	G/2 15FT SW P G-106 PRV PSV-292
EAST BULK - #40 RAW MAT.	CVS NO RD	29708	0.75	LIGHT LIQUID	1/7 15FT SW P CP-389 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	29717	0.75	LIGHT LIQUID	1/7 22FT SW P CP-389 PRV PSV-332
EAST BULK - #40 RAW MAT.	CVS NO RD	29729	0.75	LIGHT LIQUID	G/4 31FT SW P CP-389 PRV PSV-185
EAST BULK - #40 RAW MAT.	CVS NO RD	29731	0.75	LIGHT LIQUID	G/6 33FT SW P CP-389 PRV PSV-144
EAST BULK - #40 RAW MAT.	CVS NO RD	29733	0.75	LIGHT LIQUID	G/3 33FT SW P CP-389 PRV PSV-182
EAST BULK - #40 RAW MAT.	CVS NO RD	29744	0.75	LIGHT LIQUID	1/1 28FT SW P CP-794 PRV PSV-171
EAST BULK - #40 RAW MAT.	CVS NO RD	29795	0.75	LIGHT LIQUID	G/4 SWSD TK TK-154 PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	29801	0.75	LIGHT LIQUID	G/2 75FT SW BLDG 76 CONTROL ROOM PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	37151	1	LIGHT LIQUID	G/4 6FT E TK TK-200 PRV PSV-200
EAST BULK - #40 RAW MAT.	CVS NO RD	51024	10	LIGHT LIQUID	G/10 93FT NW BLDG 40 CNTRL ROOM PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	51110	10	LIGHT LIQUID	G/9 93FT NW BLDG 40 CNTRL ROOM PRV
EAST BULK - #40 RAW MAT.	CVS NO RD	51163	0.75	LIGHT LIQUID	G/3 3FT N TK TK-223 PRV PSV-745
EAST BULK - #40 RAW MAT.	CVS NO RD	53927	0.75	GAS / VAPOR	G/5 30FT E TK TK-223
EAST BULK - #40 RAW MAT.	CVS NO RD	80034	1	LIGHT LIQUID	G/3 5FT SW TK TK-296 PRV PSV-371
EAST BULK - #40 RAW MAT.	CVS NO RD	80909	1	LIGHT LIQUID	G/6 21FT W J ST&RD 7 PSV40-300
EAST BULK - #40 RAW MAT.	CVS NO RD	81315	1	LIGHT LIQUID	G/4 10FT W TK TK-202 PSV-25
EAST BULK - #40 RAW MAT.	CVS NO RD	81317	1	LIGHT LIQUID	G/3 10FT W TK TK-202 PSV-26
EAST BULK - #40 RAW MAT.	CVS NO RD	81319	1	LIGHT LIQUID	G/3 10FT W TK TK-202 PSV-703
EAST BULK - #40 RAW MAT.	CVS NO RD	81331	1	LIGHT LIQUID	G/3 SWSD TK TK-202 PSV-4
EAST BULK - #40 RAW MAT.	CVS NO RD	82728	1	LIGHT LIQUID	G/3 NESD TK TK-285 PRV PSV-801
EAST BULK - #40 RAW MAT.	CVS WITH RD	53318	2	GAS / VAPOR	G/5 6FT E TK TK-223

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11652	1	LIGHT LIQUID	G/3 4FT SE P PD-121 PRV PSV-112
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11663	1	LIGHT LIQUID	G/3 ESD P PD-121 PRV PSV-3
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11683	1	LIGHT LIQUID	G/3 3FT SE P PD-119 PRV PSV-118
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11701	1	LIGHT LIQUID	G/4 5FT E P PD-119 PRV PSV-118
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11720	1	LIGHT LIQUID	G/3 6FT NE V F-10 PRV PSV-111
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11753	1	LIGHT LIQUID	G/3 NSD V F-181 PRV PSV-120
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11760	1	LIGHT LIQUID	G/3 SSD V F-182 PRV PSV-121
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11813	1	LIGHT LIQUID	G/3 SSD V F-183 PRV PSV-122
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11818	1	LIGHT LIQUID	G/3 NSD V F-184 PRV PSV-123
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11841	2	GAS / VAPOR	T/4 T V F-183
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11873	1.5	GAS / VAPOR	1/5 NESD V F-184 PRV PSV-118
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11922	1	LIGHT LIQUID	G/4 11FT NE P G-500 PRV PSV-12 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11937	1	LIGHT LIQUID	G/2 30FT E P G-500 PRV PSV-133 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	11979	1	LIGHT LIQUID	G/6 4FT E P G-506 PRV PSV-17 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12009	1	LIGHT LIQUID	G/5 ESD P G-504 PRV PSV-33 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12023	0.75	LIGHT LIQUID	G/5 ESD P G-500 PRV PSV-79 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12028	0.75	LIGHT LIQUID	G/5 WSD P G-500 PRV PSV-91 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12051	1	LIGHT LIQUID	G/3 NWSD P PD-74 PRV PSV-103 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12058	1	LIGHT LIQUID	G/3 WSD P PD-74 PRV PSV-102 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12065	1	LIGHT LIQUID	G/3 7FT W P PD-74 PRV PSV-76 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12074	1	LIGHT LIQUID	G/6 12FT W P G-501 PRV PSV-85 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12089	1	LIGHT LIQUID	G/5 ESD P G-501 PRV PSV-80 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12102	1	LIGHT LIQUID	G/4 10FT SE P G-501 PRV PSV-7 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12113	1	LIGHT LIQUID	G/5 ESD P G-503 PRV PSV-82 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12146	1	LIGHT LIQUID	G/5 ESD P G-502 PRV PSV-81 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12181	1	LIGHT LIQUID	G/7 ESD P CP-507 PRV PSV-799
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12182	1	LIGHT LIQUID	G/5 NSD P CP-507 PRV PSV-88
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12214	1	LIGHT LIQUID	G/5 15FT NE P CP-745 PRV PSV-186
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12236	1	LIGHT LIQUID	G/5 ESD P CP-745 PRV PSV-102
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12259	1	LIGHT LIQUID	G/5 ESD P CP-746 PRV PSV-104
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12272	1	LIGHT LIQUID	G/5 11FT W P CP-746 PRV PSV-24
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12292	1	LIGHT LIQUID	G/5 ESD P-747 PRV PSV-106
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12322	1	LIGHT LIQUID	G/5 ESD P CP-744 PRV PSV-101
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12372	0.75	LIGHT LIQUID	G/4 155FT SW TK TK-169 PRV PSV-560 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12904	0.75	LIGHT LIQUID	G/5 NESD P G-1304 PRV PSV-810 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12910	0.75	LIGHT LIQUID	G/5 NESD P G-1303 PRV PSV-809
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12916	0.75	LIGHT LIQUID	G/5 NESD P G-1302 PRV PSV-808
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12922	0.75	LIGHT LIQUID	G/5 NESD P G-1301 PRV PSV-807
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12982	0.75	LIGHT LIQUID	G/4 7FT E P CP-1282 PRV PSV-797
EAST BULK - #76 GAS BLDNG.	CVS NO RD	12991	0.75	LIGHT LIQUID	G/4 7FT E P CP-1281 PRV PSV-796
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13032	0.75	LIGHT LIQUID	G/4 13FT W P G-1175 PRV PSV-127 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13059	0.75	LIGHT LIQUID	G/4 9FT W P G-1170 PRV PSV-126
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13093	0.75	LIGHT LIQUID	G/4 9FT W P G-1171 PRV PSV-125 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13131	0.75	LIGHT LIQUID	G/4 13FT W P G-1176 PRV PSV-124
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13146	0.75	LIGHT LIQUID	G/5 ESD P CP-823 PRV PSV-2
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13206	0.75	LIGHT LIQUID	G/6 24FT SE P G-18 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13224	1	LIGHT LIQUID	1/1 25FT SE P G-18 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13226	0.75	LIGHT LIQUID	G/5 10FT SE P G-459 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13235	0.75	LIGHT LIQUID	G/5 15FT SE P G-459 PRV PSV-38 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13305	1	LIGHT LIQUID	1/0 9FT NW P G-504 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13325	0.75	LIGHT LIQUID	G/4 24FT NE P G-504 PRV PSV-56
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13336	1	LIGHT LIQUID	G/3 120FT W P CP-231 PRV N
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13338	1	LIGHT LIQUID	G/3 120FT W P CP-231 PRV S
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13349	1	LIGHT LIQUID	G/5 155FT SW TK TK-174 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13368	0.75	LIGHT LIQUID	G/5 5FT SW TK TK-174 PRV PSV-788
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13387	0.75	LIGHT LIQUID	G/5 7FT E TK TK-110 PRV PSV-790
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13394	0.75	LIGHT LIQUID	G/5 6FT E TK TK-110 PRV PSV-789 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13398	0.75	LIGHT LIQUID	G/5 NESD TK TK-110 PRV PSV-781
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13403	0.75	LIGHT LIQUID	G/4 NESD TK TK-110 PRV PSV-805 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13409	0.75	LIGHT LIQUID	G/4 6FT S TK TK-160 PRV PSV-230 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13412	0.75	LIGHT LIQUID	G/4 6FT E TK TK-160 PRV PSV-19 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13426	0.75	LIGHT LIQUID	G/3 SESD TK TK-160 PRV PSV-55 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13430	1	LIGHT LIQUID	G/3 SESD TK TK-160 PRV PSV-861 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13451	1	LIGHT LIQUID	G/3 160FT SW TK TK-167 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13452	1	LIGHT LIQUID	G/3 159FT SW TK TK-167 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13455	1	LIGHT LIQUID	G/3 158FT SW TK TK-167 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13456	1	LIGHT LIQUID	G/3 157FT SW TK TK-167 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13460	1	LIGHT LIQUID	G/3 155FT SW TK TK-167 PRV PSV-458 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13484	0.75	LIGHT LIQUID	G/4 SWSD TK TK-167 PRV PSV-452
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13488	1	LIGHT LIQUID	G/3 SWSD TK TK-167 PRV PSV-448 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13500	1	LIGHT LIQUID	G/4 6FT S TK TK-167 PRV PSV-442 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13505	1	LIGHT LIQUID	G/4 6FT S TK TK-167 PRV PSV-443 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13562	1	LIGHT LIQUID	G/5 SWSD TK TK-168 PRV PSV-47 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13563	1	LIGHT LIQUID	G/4 SWSD TK TK-168 PRV PSV-120 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13574	1	LIGHT LIQUID	G/4 6FT S TK TK-168 PRV PSV-407 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13580	1	LIGHT LIQUID	G/3 6FT S TK TK-168 PRV PSV-408 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13614	1	LIGHT LIQUID	1/4 149FT SW TK TK-169 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13624	0.75	LIGHT LIQUID	G/5 SWSD TK TK-169 PRV PSV-451 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13635	0.75	LIGHT LIQUID	G/4 6FT S TK TK-169 PRV PSV-453 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13640	0.75	LIGHT LIQUID	G/4 6FT S TK TK-169 PRV PSV-455 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13646	0.75	LIGHT LIQUID	G/3 174FT SE TK TK-169 PRV PSV-43 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13648	0.75	LIGHT LIQUID	G/3 176FT SE TK TK-169 PRV PSV-47 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13649	0.75	LIGHT LIQUID	G/7 200FT SE TK TK-169 PRV PSV-766 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13684	0.75	LIGHT LIQUID	G/5 151FT N TK TK-105 PRV PSV-183 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13698	1	LIGHT LIQUID	G/5 5FT S TK TK-172 PRV PSV-563 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13711	1	LIGHT LIQUID	G/2 SSD TK TK-172 PRV PSV-546 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13715	1	LIGHT LIQUID	G/5 SSD TK TK-172 PRV PSV-517 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13720	1	LIGHT LIQUID	G/5 5FT S TK TK-172 PRV PSV-558 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13728	1	LIGHT LIQUID	G/4 WSD TK TK-170 PRV PSV-544 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13730	1	LIGHT LIQUID	G/2 WSD TK TK-170 PRV PSV-545 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13740	1	LIGHT LIQUID	G/4 SSD TK TK-170 PRV PSV-557 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13744	1	LIGHT LIQUID	G/4 SSD TK TK-170 PRV PSV-562 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13797	6	GAS / VAPOR	T/5 NESD TK F-300 PRV PSV-759
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13801	6	GAS / VAPOR	T/5 ESD TK F-300 PRV PSV-760
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13859	3	GAS / VAPOR	T/4 NESD TK F-301 PRV PSV-352
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13911	0.75	LIGHT LIQUID	G/5 5FT SW P G-325 PRV PSV-135
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13914	0.75	LIGHT LIQUID	G/4 7FT SW P G-325 PRV PSV-134
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13954	0.75	LIGHT LIQUID	G/3 7FT NW P G-321 PRV PSV-32
EAST BULK - #76 GAS BLDNG.	CVS NO RD	13968	0.75	LIGHT LIQUID	G/5 NSD P G-321 PRV PSV-13
EAST BULK - #76 GAS BLDNG.	CVS NO RD	2885	1	LIGHT LIQUID	G/5 ESD P G-506 PRV PSV-84 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	2900	1	LIGHT LIQUID	G/4 20FT W P CP-1280 PRV PSV-63
EAST BULK - #76 GAS BLDNG.	CVS NO RD	2932	0.75	LIGHT LIQUID	G/4 8FT SW P G-309 PRV PSV-181

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #76 GAS BLDNG.	CVS NO RD	50425	1	GAS / VAPOR	1/4 3FT NW V F-181 PRV PSV-119
EAST BULK - #76 GAS BLDNG.	CVS NO RD	80084	0.75	LIGHT LIQUID	G/5 NESD P G-1305 PRV RSV-811 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	82797	0.5	LIGHT LIQUID	G/3 10FT W F-10 ESD CHEM TOTE
EAST BULK - #76 GAS BLDNG.	CVS NO RD	83951	1	LIGHT LIQUID	G/4 WSD TK TK-174 PRV PSV-441 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	83953	0.75	LIGHT LIQUID	G/5 5FT SW TK TK-174 PRV PSV-444
EAST BULK - #76 GAS BLDNG.	CVS NO RD	84071	1	LIGHT LIQUID	G/7 4FT E P G-501 PRV PSV-86 PRV
EAST BULK - #76 GAS BLDNG.	CVS NO RD	84076	1	LIGHT LIQUID	G/5 9FT E P P-1280 PRV PSV-798 PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	16296	0.5	LIGHT LIQUID	G/2 21FT N P G-631 PRV PSV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	29933	0.75	LIGHT LIQUID	G/4 7FT NE P G-631 PRV PSV 86
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	29959	0.75	LIGHT LIQUID	G/5 10FT NW P G-631 PRV PSV-90
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	29981	0.75	LIGHT LIQUID	G/4 7FT NE P G-630 PRV PSV-84
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30005	1	LIGHT LIQUID	G/12 9FT N P G-4 PRV PSV-1440
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30016	1	LIGHT LIQUID	G/5 17FT SW P G-3 PRV PSV-31
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30025	1	LIGHT LIQUID	G/9 4FT S P G-101 PRV PSV-39
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30043	1	LIGHT LIQUID	G/2 20FT NW P G-101 PRV PSV-29
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30119	1	LIGHT LIQUID	G/9 13FT E P G-2 PRV PSV-16
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30126	1	LIGHT LIQUID	G/9 17FT E P G-1 PRV PSV-15
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30159	0.75	LIGHT LIQUID	G/6 18FT S P G-101 PRV PSV-31
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30182	0.75	LIGHT LIQUID	G/6 6FT W P G-3 PRV PSV-43
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30189	0.75	LIGHT LIQUID	G/6 8FT NW P G-3 PRV PSV-23
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30238	0.75	LIGHT LIQUID	G/5 13FT NE P G-7 PRV PSV-1
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30254	0.75	LIGHT LIQUID	G/9 25FT NE P G-7 PRV PSV-4
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30259	0.75	LIGHT LIQUID	G/4 23FT NE P G-7 PRV PSV-2
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30271	0.75	LIGHT LIQUID	G/5 24FT N P G-7 PRV PSV-3
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30309	0.75	LIGHT LIQUID	G/5 5FT NW P G-5 PRV PSV-12
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30315	0.75	LIGHT LIQUID	G/5 4FT NW P G-5 PRV PSV-9
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30319	0.75	LIGHT LIQUID	G/5 3FT NW P G-5 PRV PSV-10
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30328	0.75	LIGHT LIQUID	G/3 13FT NW P G-5 PRV PSV-22
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30330	0.75	LIGHT LIQUID	G/3 12FT NW P G-5 PRV PSV-23
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30332	0.75	LIGHT LIQUID	G/9 11FT NW P G-5 PRV PSV-46
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30338	0.75	LIGHT LIQUID	G/5 26FT NW P G-5 PRV PSV-13
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30343	0.75	LIGHT LIQUID	G/7 15FT N P G-2 PRV PSV-47
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30349	0.75	LIGHT LIQUID	G/7 15FT N P G-2 PRV PSV-48
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30356	0.75	LIGHT LIQUID	G/5 20FT NW P G-2 PRV PSV-33

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30360	0.75	LIGHT LIQUID	G/5 25FT NW P G-2 PRV PSV-35
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30364	0.75	LIGHT LIQUID	G/5 25FT NE P G-101 PRV PSV-32
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30369	0.75	LIGHT LIQUID	G/5 ESD WEST BATT LIMIT
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30380	0.75	LIGHT LIQUID	G/3 MID WEST BATT LIMIT PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30392	0.75	LIGHT LIQUID	G/4 WSD WEST BATT LIMIT PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30404	0.75	LIGHT LIQUID	G/5 NSD WEST BATT LIMIT PRV PSV-51
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30476	0.75	LIGHT LIQUID	G/3 SWSD TK TK-292 PRV PSV-240
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30489	0.75	LIGHT LIQUID	G/5 6FT W TK TK-292 PRV PSV-855
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30497	0.75	LIGHT LIQUID	G/5 6FT W TK TK-292 PRV PSV-854
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30502	0.75	LIGHT LIQUID	G/3 NWSD TK TK-101 PRV PSV-85
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30520	0.75	LIGHT LIQUID	G/4 8FT W TK TK-210 PRV PSV-712
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30524	0.75	LIGHT LIQUID	G/3 8FT W TK TK-210 PRV PSV-713
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30544	0.75	LIGHT LIQUID	G/5 10FT S TK TK-241 PRV PSV-111
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30562	0.75	LIGHT LIQUID	G/4 SWSD TK TK-241 PRV PSV-100
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30608	0.75	LIGHT LIQUID	G/4 8FT W TK TK-243 PRV PSV-784
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30616	0.75	LIGHT LIQUID	G/4 8FT W TK TK-243 PRV PSV-785
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30636	2	GAS / VAPOR	G/5 10FT SW TK TK-281 PRV PCV-623
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30678	0.75	LIGHT LIQUID	G/4 SSD TK TK-287 PRV PSV-567
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30681	0.75	LIGHT LIQUID	G/4 SSD TK TK-287 PRV PSV-565
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30689	0.75	LIGHT LIQUID	G/3 SWSD TK TK-287 PRV PSV-577
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30691	0.75	LIGHT LIQUID	G/4 SWSD TK TK-287 PRV PSV-575
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30849	0.75	LIGHT LIQUID	G/4 SSD TK TK-1007 PRV PSV-787
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	30857	0.75	LIGHT LIQUID	G/4 SSD TK TK-1007 PRV PSV-795
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31001	1	LIGHT LIQUID	G/3 115FT S TK TK-1001 PRV PSV-765
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31003	1	LIGHT LIQUID	G/3 113FT S TK TK-1001 PRV PSV-150
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31007	1	LIGHT LIQUID	G/3 112FT S TK TK-1001 PRV PSV-505
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31010	1	LIGHT LIQUID	G/3 111FT S TK TK-1001 PRV PSV-502
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31012	1	LIGHT LIQUID	G/3 110FT S TK TK-1001 PRV PSV-500
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31018	1	LIGHT LIQUID	G/3 114FT S TK TK-1001 PRV PSV-676
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31074	0.75	LIGHT LIQUID	G/3 80FT NW BLDG 80 CONTROL ROOM PRV PSV-52
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31122	0.75	LIGHT LIQUID	G/2 60FT N BLDG 80 CONTROL ROOM PRV PSV-20
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31128	0.75	GAS / VAPOR	G/7 50FT NE BLDG 80 CONTROL ROOM PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31161	0.75	LIGHT LIQUID	G/2 20FT NW CNR F ST. & ROAD 8 PRV PSV-18
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31163	0.75	LIGHT LIQUID	G/2 21FT NW CNR F ST. & ROAD 8 PRV PSV-17

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31165	0.75	LIGHT LIQUID	G/11 25FT NW CNR F ST. & ROAD 8 PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31244	0.75	LIGHT LIQUID	G/7 65FT NE TK TK-203 PRV PSV-748
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31278	0.75	LIGHT LIQUID	G/2 20FT NE CNR J ST & ROAD 8 PRV PSV-593
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31283	0.75	LIGHT LIQUID	G/3 18FT NE CNR J ST & ROAD 8 PRV PSV-174
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31317	0.75	LIGHT LIQUID	G/2 87FT E CNR J ST & ROAD 8 PRV PSV-714
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31330	0.75	LIGHT LIQUID	G/2 5FT NE CNR M ST & ROAD 8 PRV PSV-820
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31332	0.75	LIGHT LIQUID	G/2 20FT NE CNR M ST & ROAD 8 PRV PSV-574
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31337	0.75	LIGHT LIQUID	G/-3 20FT E CNR M ST & ROAD 8 NWSD LN 501
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31347	0.75	LIGHT LIQUID	G/-1 29FT E CNR M ST & ROAD 8 SWSD LN 301
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31355	0.75	LIGHT LIQUID	G/3 33FT E CNR M ST & ROAD 8 PRV PSV-512
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31357	0.75	LIGHT LIQUID	G/3 33FT NE CNR M ST & ROAD 8 PRV PSV-521
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31360	0.75	LIGHT LIQUID	G/3 34FT NE CNR M ST & ROAD 8 PRV PSV-524
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31362	0.75	LIGHT LIQUID	G/3 35FT NE CNR M ST & ROAD 8 PRV PSV-513
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31364	0.75	LIGHT LIQUID	G/3 38FT NE CNR M ST & ROAD 8 PRV PSV-503
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31366	0.75	LIGHT LIQUID	G/3 39FT NE CNR M ST & ROAD 8 PRV PSV-571
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31368	0.75	LIGHT LIQUID	G/3 45FT NE CNR M ST & ROAD 8 PRV PSV-718
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31413	0.75	LIGHT LIQUID	G/3 57FT E CNR M ST & ROAD 8 PRV PSV-513
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31415	0.75	LIGHT LIQUID	G/3 58FT E CNR M ST & ROAD 8 PRV PSV-670
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31417	0.75	LIGHT LIQUID	G/5 60FT NE CNR M ST & ROAD 8 PRV PSV-426
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31418	0.75	LIGHT LIQUID	G/5 61FT NE CNR M ST & ROAD 8 PRV PSV-427
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31425	0.75	LIGHT LIQUID	G/3 63FT NE CNR M ST & ROAD 8 PRV PSV-569
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31537	0.75	LIGHT LIQUID	G/4 50FT S TK TK-288 PRV PSV-767
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31544	0.75	LIGHT LIQUID	G/5 51FT S TK TK-288 PRV PSV-763
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31551	0.75	LIGHT LIQUID	G/11 20FT NE CNR F ST. & ROAD 8 PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31553	0.75	LIGHT LIQUID	G/7 57FT N TK TK-201 PRV PSV-732
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31554	0.75	LIGHT LIQUID	G/7 58FT NW TK TK-201 PRV PSV-731
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	31564	0.75	LIGHT LIQUID	G/-2 52FT E CNR M ST & ROAD 8 SWSD LN 309 PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	34392	1	LIGHT LIQUID	G/14 10FT NW P G-630 PRV PSV-83
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	34399	1	LIGHT LIQUID	G/2 9FT W P G-5 PRV PSV-89
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	37778	1	LIGHT LIQUID	G/14 12FT NW P G-630 PRV PSV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	50052	1	LIGHT LIQUID	G/4 SSD TK TK-1004 PRV PSV-530
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	50065	0.75	LIGHT LIQUID	G/4 3FTS TK TK-1004 PRV PSV-528
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	50894	1	LIGHT LIQUID	G/3 2FT S TK TK-1003 PRV
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	50910	1	LIGHT LIQUID	G/4 4FT SE TK TK-1003 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	52412	0.75	LIGHT LIQUID	G/3 5FT S TK TK-1002 PRV PSV-532
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	52418	0.75	LIGHT LIQUID	G/3 SESD TK TK-1002 PRV PSV--536
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	80547	0.75	LIGHT LIQUID	G/6 10FT NE CNR F ST. & ROAD 8 PRV PSV-66
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	80548	0.75	LIGHT LIQUID	G/3 18FT NE CNR J ST & ROAD 8 PRV PSV-470
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81138	1	LIGHT LIQUID	G/8 18FT S P G-101
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81444	0.75	LIGHT LIQUID	G/4 9FT S TK TK-241 PRV PSV-74
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81521	0.75	LIGHT LIQUID	G/3 6FT E TK TK-242 PRV PSV-852
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81522	0.75	LIGHT LIQUID	G/3 6FT E TK TK-242 PRV PSV-496
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81633	0.75	LIGHT LIQUID	G/6 SESD TK TK-291 PRV PSV-245
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81651	0.75	LIGHT LIQUID	G/4 6FT E TK TK-291 ESD PFRM PSV-1013
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81653	0.75	LIGHT LIQUID	G/4 6FT E TK TK-291 ESD PFRM PSV-1013
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	81807	1	LIGHT LIQUID	G/3 13FT SE P G-2 PRV PSV-6
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	82023	0.75	LIGHT LIQUID	G/4 6FT N TK TK-101 PRV PSV-11
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	82024	0.75	LIGHT LIQUID	G/4 6FT N TK TK-101 PRV PSV-10
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	82734	0.75	LIGHT LIQUID	G/4 SSD TK TK-1001 PRV PSV-51
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	82803	0.75	LIGHT LIQUID	G/4 SWSD TK TK-1001 PRV PSV-537
EAST BULK - #80 REF. OIL SHIPG.	CVS NO RD	83318	0.75	LIGHT LIQUID	G/5 NWSD TK TK-210 PRV PSV-723
EAST BULK - #80 REF. OIL SHIPG.	CVS WITH RD	50951	6	GAS / VAPOR	T/2 ESD TK F-833 PRV PSV-47
EAST BULK - #80 REF. OIL SHIPG.	CVS WITH RD	50953	6	GAS / VAPOR	T/2 ESD TK F-833 SSD PRV PSV-48
HYDROCRACKER - #246	CVS NO RD	29922	0.5	GAS / VAPOR	G/5 SESD AH 246-AT-003 PRV PSV-300
HYDROCRACKER - #246	CVS NO RD	4603	1	GAS / VAPOR	G/5 23FT SE V V-806 PRV 8PSV-78
HYDROCRACKER - #246	CVS NO RD	4631	1	GAS / VAPOR	G/5 24FT S V V-806 PRV 8PSV-79 PRV
HYDROCRACKER - #246	CVS NO RD	50703	3	GAS / VAPOR	1/5 30FT NW P 8G-817B PRV
HYDROCRACKER - #246	CVS NO RD	50704	2	GAS / VAPOR	2/5 30FT NW P 8G-817B PRV
HYDROCRACKER - #246	CVS NO RD	50707	2	GAS / VAPOR	2/4 34FT NW P 8G-817B PRV
HYDROCRACKER - #246	CVS NO RD	50943	2	GAS / VAPOR	1/2 13FT W E 8E-804 PRV PSV-121
HYDROCRACKER - #246	CVS NO RD	5116	6	GAS / VAPOR	4/9 6FT S FF 8E-826B PRV PSV-4
HYDROCRACKER - #246	CVS NO RD	5128	6	GAS / VAPOR	4/7 6FT S FF 8E-826C PRV PSV-7
HYDROCRACKER - #246	CVS NO RD	51578	3	GAS / VAPOR	4/6 6FT SW FF 8E-826A PRV PSV-6
HYDROCRACKER - #246	CVS NO RD	5161	6	GAS / VAPOR	4/7 6FT N FF 8E-828C PRV 8PSV-27B PRV
HYDROCRACKER - #246	CVS NO RD	5170	6	GAS / VAPOR	4/7 6FT N FF 8E-828C PRV 8PSV-27A PRV
HYDROCRACKER - #246	CVS NO RD	5175	8	GAS / VAPOR	4/7 20FT N E 8E-834 PRV 8PSV-30B PRV
HYDROCRACKER - #246	CVS NO RD	5185	6	GAS / VAPOR	4/7 20FT N E 8E-834 PRV 8PSV-30A PRV
HYDROCRACKER - #246	CVS NO RD	5190	3	GAS / VAPOR	4/6 6FT N FF 8E-828A PRV PV-29 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
HYDROCRACKER - #246	CVS NO RD	5209	8	GAS / VAPOR	4/7 6FT N FF 8E-826C PRV 8PSV-3 PRV
HYDROCRACKER - #246	CVS NO RD	5217	4	GAS / VAPOR	4/6 6FT N FF 8E-819B PRV 8PSV-5A PRV
HYDROCRACKER - #246	CVS NO RD	5222	4	GAS / VAPOR	4/6 6FT N FF 8E-819B PRV 8PSV-5B PRV
HYDROCRACKER - #246	CVS NO RD	60086	3	GAS / VAPOR	4/6 6FT N FF 8E-826D PRV 8PSV-12 PRV
HYDROCRACKER - #246	CVS NO RD	6082	4	GAS / VAPOR	T/6 ESD V 8F-802 PRV PSV-1
HYDROCRACKER - #246	CVS NO RD	80331	1.5	GAS / VAPOR	4/4 8FT S FF 8E-818C PRV PSV-42
HYDROCRACKER - #246	CVS NO RD	80397	3	GAS / VAPOR	4/6 6FT N FF 8E-828A PRV 8PSV-31 PRV
HYDROCRACKER - #246	CVS NO RD	84811	1	LIGHT LIQUID	3/4 SWSD V 8F-808 PRV PSV-75
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	11592	0.25	GAS / VAPOR	G/2 8FT N P G-555A PRV PSV-918
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19036	2	LIGHT LIQUID	G/3 11FT NE P G-310 PRV PCV-455
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19080	1	LIGHT LIQUID	G/12 18FT NW P G-310 PRV PRV-919
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19097	2	LIGHT LIQUID	1/4 12FT N E E-317 SSD PFRM PRV
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19338	4	GAS / VAPOR	G/30 10FT SE V F-560 PRV-539
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19340	2	GAS / VAPOR	G/30 10FT S V F-560 PRV PSV-385
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19342	1	GAS / VAPOR	G/30 15FT S C GB-522 PRV PSV-546
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19347	1	GAS / VAPOR	G/30 12FT SE E E-562 PRV PSV-544
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19349	1.5	GAS / VAPOR	G/30 12FT S E E-562 PRV PSV-545
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19671	2	GAS / VAPOR	4/4 7FT NE V F-545 PRV PSV-570
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19682	1.5	GAS / VAPOR	1/6 SSD V F-522 PRV PSV-513
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19698	1.5	GAS / VAPOR	1/6 SSD V F-525 PRV PSV-515
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19722	1.5	GAS / VAPOR	1/6 NSD V F-524 PRV PSV-516
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19731	1.5	GAS / VAPOR	1/6 NSD V F-523 PRV PSV-514
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19755	4	GAS / VAPOR	1/6 WSD V F-520 PRV
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19780	1.5	GAS / VAPOR	1/6 WSD V D-521 PRV
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	19986	4	GAS / VAPOR	1/5 6FT E V F-523 PRV PSV-512
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	20006	4	GAS / VAPOR	2/2 SESD E E-524B PSV-404
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	20011	4	GAS / VAPOR	2/3 NWSD E E-524B PSV-519
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	20110	1.5	GAS / VAPOR	1/6 NSD V F-526 PSV-518
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	20124	2	GAS / VAPOR	1/6 ESD V F-526 PSV-522
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	20972	6	GAS / VAPOR	3/4 NESD T D-511 PRV PSV-502
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21117	3	GAS / VAPOR	T/4 MID T F-510 PRV PSV-501
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21359	1.5	LIGHT LIQUID	G/4 22FT N P G-540A PRV PSV-914
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21674	1.5	GAS / VAPOR	G/3 5FT S V F-533 PRV PSV-538
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21678	1.5	GAS / VAPOR	G/2 5FT S V F-532 PRV PSV-537

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21682	1.5	GAS / VAPOR	G/2 5FT S V F-531 PRV PSV-536
MP30/SULFUR - #228 ISOMERIZATION	CVS NO RD	21686	1.5	GAS / VAPOR	G/2 4FT S V F-530 PRV PSV-535
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20439	3	GAS / VAPOR	3/4 NSD T D-535 PRV PSV-523
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20545	2	GAS / VAPOR	2/3 NWSD E E-536B PRV PSV-525
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20548	1	GAS / VAPOR	2/3 NESD E E-540 PRV PSV-529
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20694	1.5	GAS / VAPOR	1/7 SESD T D-540 PRV
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20866	2	GAS / VAPOR	T/4 ESD V F-512 PRV PSV-503
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20888	2	GAS / VAPOR	T/4 SWSD V F-512 PRV PSV-609
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20889	1	GAS / VAPOR	T/4 SWSD V F-512 PRV PSV-611
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20890	1	GAS / VAPOR	T/4 SWSD V F-512 PRV PSV-612
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20891	2.5	GAS / VAPOR	T/4 SWSD V F-512 PRV PSV-610
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20895	2	LIGHT LIQUID	T/4 NWSD V F-512 PRV PSV-913
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	20896	2	LIGHT LIQUID	T/4 NWSD V F-512 PRV PSV-911
MP30/SULFUR - #228 ISOMERIZATION	CVS WITH RD	21592	3	GAS / VAPOR	3/5 SWSD T D-546 PRV PSV-881
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31624	0.75	GAS / VAPOR	2/5 13FT S FF E-934A PRV PSV-935
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31625	3	GAS / VAPOR	2/6 15FT S FF E-934A PRV PSV-934
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31641	6	GAS / VAPOR	3/6 NESD FF E-934A PRV PSV-936
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31685	6	GAS / VAPOR	T/6 ESD T D-803 PRV PSV-27
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31757	6	GAS / VAPOR	1/2 SSD V F-817 PRV PSV-100
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31760	2	GAS / VAPOR	1/6 9FT NE V F-803 PRV PSV-494C
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31783	8	GAS / VAPOR	1/4 NWSD V F-803 PRV PSV-12
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31854	6	GAS / VAPOR	T/4 SSD V F-809 PRV PSV-21
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31857	6	GAS / VAPOR	T/4 SSD V F-809 PRV PSV-20
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	31908	4	GAS / VAPOR	G/35 SWSD P HC-3201 PRV PSV-19
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43612	4	GAS / VAPOR	3/4 NESD T D-911 PRV PSV-10
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43689	4	GAS / VAPOR	1/4 10FT N V F-902 PRV PSV-8
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43765	2	GAS / VAPOR	1/0 SSD V F-107 PRV PSV-10
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43810	6	GAS / VAPOR	3/6 ESD T D-901 PRV PSV-8
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43836	0.75	GAS / VAPOR	2/8 5FT NW E E-902 PRV PSV-4
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43845	1.5	GAS / VAPOR	2/5 NSD V F-703 PRV PSV2
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43985	3	GAS / VAPOR	2/6 TOP V F-921 PRV PSV-517
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	43996	3	GAS / VAPOR	2/3 SWSD T D-921 PRV PSV-519
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	50179	2	GAS / VAPOR	2/4 NSD F-701 PRV PSV-1
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	50219	3	GAS / VAPOR	1/7 MID V F-10 PRV PSV-11

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	52740	3	GAS / VAPOR	2/3 10FT SE V F-801
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	81437	3	GAS / VAPOR	T/1 SSD TK-805 PSV
MP30/SULFUR - #236 SULFUR PLANT	CVS NO RD	81450	1	GAS / VAPOR	1/3 NSD FF E-922 PRV PSV-518
MP30/SULFUR - #236 SULFUR PLANT	CVS WITH RD	50266	4	GAS / VAPOR	1/5 5FT W V F-903 PRV PSV-1
MP30/SULFUR - #238 SULFUR PLANT	CVS NO RD	81456	1.5	GAS / VAPOR	1/4 ABV V F-601 PRV PSV-1
MP30/SULFUR - #238 SULFUR PLANT	CVS NO RD	81458	1.5	GAS / VAPOR	1/4 ABV V F-602 PRV PSV-2
MP30/SULFUR - (229-230-231)	CVS NO RD	14983	4	GAS / VAPOR	G/5 SSD C GB-201B PRV PSV-18 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	15044	3	GAS / VAPOR	1/5 MID V F-204 PRV PSV-209 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	15050	3	GAS / VAPOR	1/5 MID V F-204 PRV PSV-209A PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	15509	1	GAS / VAPOR	1/5 SSD V F-303 PRV PSV-4 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	15616	2	GAS / VAPOR	1/7 WSD V F-302 PRV PSV-5 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	15687	3	GAS / VAPOR	G/8 SSD C GB-301A
MP30/SULFUR - (229-230-231)	CVS NO RD	15869	2	GAS / VAPOR	G/8 PRV FF D-310
MP30/SULFUR - (229-230-231)	CVS NO RD	15916	1	GAS / VAPOR	G/15 10FT S V F-201A-2A 10FT SW C GM-201A
MP30/SULFUR - (229-230-231)	CVS NO RD	15923	1	GAS / VAPOR	G/19 SWSD V F-212 PRV PSV-44
MP30/SULFUR - (229-230-231)	CVS NO RD	16015	2	LIGHT LIQUID	G/20 ESD P G-104
MP30/SULFUR - (229-230-231)	CVS NO RD	16063	1	GAS / VAPOR	G/15 NSD E E-314 PRV PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	16129	3	LIGHT LIQUID	G/20 NWSD P G-205 PRV PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	16419	3	GAS / VAPOR	G/6 20FT NW P G-400 PRV PSV-10
MP30/SULFUR - (229-230-231)	CVS NO RD	17013	1	GAS / VAPOR	G/10 WSD TK F-112 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	17017	1	GAS / VAPOR	G/10 WSD TK F-122 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	17361	3	GAS / VAPOR	3/5 SESD T D-140
MP30/SULFUR - (229-230-231)	CVS NO RD	17736	3	GAS / VAPOR	1/11 TOP V F-210 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	17757	3	GAS / VAPOR	T/6 WSD T D-303 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	18057	3	GAS / VAPOR	4/5 TOP T D-208 PRV PSV-38
MP30/SULFUR - (229-230-231)	CVS NO RD	18060	3	GAS / VAPOR	5/1 SSD T D-202 PRV PSV-17
MP30/SULFUR - (229-230-231)	CVS NO RD	18127	0.5	LIGHT LIQUID	G/6 SSD E E-219 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	18271	3	GAS / VAPOR	T/3 SSD V F-213 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	18523	2	GAS / VAPOR	G/13 SWSD V F-106 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	18807	0.5	LIGHT LIQUID	G/2 SWSD P G-123 PRV PSV-72
MP30/SULFUR - (229-230-231)	CVS NO RD	18808	0.5	LIGHT LIQUID	G/2 ABV P G-121 PRV PSV-5
MP30/SULFUR - (229-230-231)	CVS NO RD	53400	4	GAS / VAPOR	T/5 NWSD RX D-101 PSV-49
MP30/SULFUR - (229-230-231)	CVS NO RD	81919	6	GAS / VAPOR	T/3 MID V F-102 PRV PSV-9
MP30/SULFUR - (229-230-231)	CVS NO RD	82004	0.75	GAS / VAPOR	T/4 NESD V F-102 PRV PSV-16 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
MP30/SULFUR - (229-230-231)	CVS NO RD	82513	3	GAS / VAPOR	T/2 WSD V D-105 PRV PSV-106
MP30/SULFUR - (229-230-231)	CVS NO RD	82563	4	GAS / VAPOR	G/5 SSD C GB-201A PRV PSV-15 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	83141	4	GAS / VAPOR	G/4 SSD C GB-301 PRV PSV-7
MP30/SULFUR - (229-230-231)	CVS NO RD	83222	6	GAS / VAPOR	T/3 ESD V D-106 PRV PSV-107A
MP30/SULFUR - (229-230-231)	CVS NO RD	83225	6	GAS / VAPOR	T/3 ESD V D-106 PRV PSV-107B
MP30/SULFUR - (229-230-231)	CVS NO RD	83237	3	GAS / VAPOR	4/7 WSD T D-302 PRV PSV-1
MP30/SULFUR - (229-230-231)	CVS NO RD	83422	6	GAS / VAPOR	3/3 SSD V D-205 PRV
MP30/SULFUR - (229-230-231)	CVS NO RD	83606	4	LIGHT LIQUID	2/5 8FT S E E-226 PRV PSV-57
MP30/SULFUR - (229-230-231)	CVS NO RD	84223	4	LIGHT LIQUID	T/1 SSD V D-201 PRV PSV-19
UNICRACKER - #240 UNICRACKER	CVS NO RD	07105	2	GAS / VAPOR	3/3 12FT W C GB-203A PRV 2PSV-5
UNICRACKER - #240 UNICRACKER	CVS NO RD	09700	6	GAS / VAPOR	3/4 ESD T 3D-301 PRV PSV-34
UNICRACKER - #240 UNICRACKER	CVS NO RD	09800	6	GAS / VAPOR	3/4 ESD T 3D-301 PRV PSV-34
UNICRACKER - #240 UNICRACKER	CVS NO RD	32706	2	GAS / VAPOR	1/4 8FT SE V 31F-45 PRV 31PSV-39
UNICRACKER - #240 UNICRACKER	CVS NO RD	37613	3	GAS / VAPOR	3/4 8FT E V 1F-107 PRV PSV-24
UNICRACKER - #240 UNICRACKER	CVS NO RD	37666	1	GAS / VAPOR	G/7 TOP V 1F-112 PRV PSV-20
UNICRACKER - #240 UNICRACKER	CVS NO RD	37812	3	GAS / VAPOR	G/9 NESD E 2E-216 PRV PSV-12
UNICRACKER - #240 UNICRACKER	CVS NO RD	38114	3	GAS / VAPOR	3/4 13FT W C GB-203A PRV 2PSV-3
UNICRACKER - #240 UNICRACKER	CVS NO RD	38208	3	GAS / VAPOR	1/5 SESD E 3FF-335 PRV PSV-69
UNICRACKER - #240 UNICRACKER	CVS NO RD	38412	2	GAS / VAPOR	T/7 NESD V 2F-201 PRV 2PSV-54
UNICRACKER - #240 UNICRACKER	CVS NO RD	38465	3	GAS / VAPOR	2/6 25FT NE V 2F-201 PRV PSV-30
UNICRACKER - #240 UNICRACKER	CVS NO RD	38470	3	GAS / VAPOR	2/7 28FT NE V 2F-201 PRV PSV-31
UNICRACKER - #240 UNICRACKER	CVS NO RD	39014	3	GAS / VAPOR	G/20 WSD E 2E-212A PRV
UNICRACKER - #240 UNICRACKER	CVS NO RD	39614	8	GAS / VAPOR	T/7 MID T 3D-301 PRV PSV-96
UNICRACKER - #240 UNICRACKER	CVS NO RD	39811	1.5	GAS / VAPOR	2/7 WSD V 3F-304 PRV PSV-23
UNICRACKER - #240 UNICRACKER	CVS NO RD	40789	3	GAS / VAPOR	2/-5 12FT W T 2F-202 PRV PSV-4
UNICRACKER - #240 UNICRACKER	CVS NO RD	40816	1.5	GAS / VAPOR	1/5 SSD FF 3E-310 PRV PSV-68
UNICRACKER - #240 UNICRACKER	CVS NO RD	40821	2	GAS / VAPOR	1/5 SSD FF 3E-310 PRV PSV-69
UNICRACKER - #240 UNICRACKER	CVS NO RD	40824	1.5	GAS / VAPOR	1/5 SSD FF 3E-310 PRV PSV-74
UNICRACKER - #240 UNICRACKER	CVS NO RD	40832	6	GAS / VAPOR	2/5 NSD FF 3E-310 PRV PSV-46
UNICRACKER - #240 UNICRACKER	CVS NO RD	40836	8	GAS / VAPOR	3/2 NSD FF 3E-310 PRV PSV-8E
UNICRACKER - #240 UNICRACKER	CVS NO RD	40838	8	GAS / VAPOR	3/2 NSD FF 3E-310 PRV PSV-8D
UNICRACKER - #240 UNICRACKER	CVS NO RD	40839	8	GAS / VAPOR	3/2 NSD FF 3E-310 PRV PSV-8C
UNICRACKER - #240 UNICRACKER	CVS NO RD	40841	8	GAS / VAPOR	3/2 NSD FF 3E-310 PRV PSV-8B
UNICRACKER - #240 UNICRACKER	CVS NO RD	40842	8	GAS / VAPOR	3/2 NSD FF 3E-310 PRV PSV-8A

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
UNICRACKER - #240 UNICRACKER	CVS NO RD	40859	2	GAS / VAPOR	G/30 10FT S E 3E-302 PRV
UNICRACKER - #240 UNICRACKER	CVS NO RD	42565	4	GAS / VAPOR	2/4 6FT NESE T 4D-401 PRV PSV-1
UNICRACKER - #240 UNICRACKER	CVS NO RD	42567	3	GAS / VAPOR	2/4 4FT SE T 4D-402 PRV PSV-5
UNICRACKER - #240 UNICRACKER	CVS NO RD	43026	1	GAS / VAPOR	G/4 20FT NE C 4G-425 INSIDE AH ATO-437/438 PRV
UNICRACKER - #240 UNICRACKER	CVS NO RD	43033	1	GAS / VAPOR	G/5 4FT E V 4F-437 PRV 4PSV-63
UNICRACKER - #240 UNICRACKER	CVS NO RD	43054	1	GAS / VAPOR	G/5 SSD V 4F-437 PRV 4PSV-64
UNICRACKER - #240 UNICRACKER	CVS NO RD	50411	1	GAS / VAPOR	G/20 ESD V 3F-305
UNICRACKER - #240 UNICRACKER	CVS NO RD	50412	1	GAS / VAPOR	G/20 ESD V 3F-305
UNICRACKER - #240 UNICRACKER	CVS NO RD	51535	6	GAS / VAPOR	T/4 TOP T 4D-411 PRV PSV-77
UNICRACKER - #240 UNICRACKER	CVS NO RD	53165	6	GAS / VAPOR	T/5 CENTER OF 3F-306 PSV
UNICRACKER - #240 UNICRACKER	CVS NO RD	53166	10	GAS / VAPOR	T/5 CENTER OF 3F-306
UNICRACKER - #240 UNICRACKER	CVS NO RD	53505	6	GAS / VAPOR	T/5 MID T 2F-202 PRV PSV-29
UNICRACKER - #240 UNICRACKER	CVS NO RD	53510	3	GAS / VAPOR	3/4 15FT W C GB-203B PRV PSV-9
UNICRACKER - #240 UNICRACKER	CVS NO RD	53550	3	GAS / VAPOR	2/4 WSD T 3D-303 PRV PSV-6
UNICRACKER - #240 UNICRACKER	CVS NO RD	53800	3	GAS / VAPOR	3/5 7FT NE V 2F-203 WSD PRV
UNICRACKER - #240 UNICRACKER	CVS NO RD	53844	3	GAS / VAPOR	3/4 15FT W C GB-203B PRV PSV-11
UNICRACKER - #240 UNICRACKER	CVS NO RD	60100	4	GAS / VAPOR	3/4 8FT W V 1F-105 PRV PSV-13
UNICRACKER - #240 UNICRACKER	CVS NO RD	84226	2	GAS / VAPOR	2/4 SESD T 4D-402 PRV PSV-2
UNICRACKER - #240 UNICRACKER	CVS WITH RD	38115	2	GAS / VAPOR	3/4 15FT W C GB-203A PRV 2PSV-7
UNICRACKER - #240 UNICRACKER	CVS WITH RD	60403	6	LIGHT LIQUID	T/5 ABV SSD E E-124 PRV PSV-4
UNICRACKER - #244 REFORMING	CVS NO RD	35362	1	GAS / VAPOR	2/3 20FT N H 5B-505 PRV PSV-15
UNICRACKER - #244 REFORMING	CVS NO RD	35585	1.5	GAS / VAPOR	2/4 NSD FF 5E-505 PRV PSV-29
UNICRACKER - #244 REFORMING	CVS NO RD	35659	4	GAS / VAPOR	2/3 TOP V 5F-502 PRV PSV-3
UNICRACKER - #244 REFORMING	CVS NO RD	35928	1	GAS / VAPOR	1/6 TOP V 5F-526 PRV PSV-526
UNICRACKER - #244 REFORMING	CVS NO RD	35950	1.5	GAS / VAPOR	1/7 WSD V 5F-527 PRV PSV-527
UNICRACKER - #244 REFORMING	CVS NO RD	36268	2	GAS / VAPOR	2/4 48FT N H 5B-507 PRV PSV-33
UNICRACKER - #244 REFORMING	CVS NO RD	51227	0.25	GAS / VAPOR	1/6 7FT NW V 5F-503 NSD INST
UNICRACKER - #244 REFORMING	CVS NO RD	53767	6	GAS / VAPOR	6/3 TOP T 5D-506 PRV PSV-7244
UNICRACKER - #244 REFORMING	CVS NO RD	53769	2	GAS / VAPOR	2/3 SSD FF 5E-505 PRV PSV-34
UNICRACKER - #244 REFORMING	CVS NO RD	60395	2	GAS / VAPOR	1/5 WSD V 5F-503 PRV PSV-6
UNICRACKER - #244 REFORMING	CVS NO RD	80340	0.5	LIGHT LIQUID	G/4 5FT N V 5F-506 PRV PSV-9
UNICRACKER - #248 UNISAR	CVS NO RD	36568	4	GAS / VAPOR	2/7 TOP V 6F-602
UNICRACKER - #248 UNISAR	CVS NO RD	36594	1	GAS / VAPOR	2/7 SWSD V 6F-602
UNICRACKER - #248 UNISAR	CVS NO RD	36738	1.5	GAS / VAPOR	2/7 10FT E V 6F-605 PRV PSV-8

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
UNICRACKER - #248 UNISAR	CVS NO RD	36902	1	GAS / VAPOR	G/12 NSD P 6G-606B
UNICRACKER - #248 UNISAR	CVS NO RD	36972	6	GAS / VAPOR	2/7 NESD V 6F-606 PRV 6PSV-18
UNICRACKER - #248 UNISAR	CVS NO RD	37027	4	GAS / VAPOR	1/3 NWSD FF E-502A PRV PRV-9
UNICRACKER - #248 UNISAR	CVS NO RD	37117	6	GAS / VAPOR	G/30 15FT SW E 6E-603 PRV
UNICRACKER - #248 UNISAR	CVS NO RD	50191	3	GAS / VAPOR	2/6 WSD V 6F-601 PRV PSV-12
UNICRACKER - #248 UNISAR	CVS NO RD	53526	1.5	GAS / VAPOR	2/7 10FT W V 6F-605 PRV PSV-7
UNICRACKER- #250 ULSD	CVS NO RD	1286	3	GAS / VAPOR	2/5 8FT E V D-714 PRV PSV-34
UNICRACKER- #250 ULSD	CVS NO RD	1289	3	GAS / VAPOR	2/5 10FT NE V D-714 PRV PSV-41
UNICRACKER- #250 ULSD	CVS NO RD	1296	2	GAS / VAPOR	2/10 ESD V D-714 PRV PSV-40
UNICRACKER- #250 ULSD	CVS NO RD	1479	4	GAS / VAPOR	1/4 SSD V D-702 PRV PSV-4
UNICRACKER- #250 ULSD	CVS NO RD	1486	3	GAS / VAPOR	1/4 WSD FF EF-704D PRV PSV-9
UNICRACKER- #250 ULSD	CVS NO RD	1690	1	GAS / VAPOR	1/5 5FT NE RX D-703 PRV PSV-6
UNICRACKER- #250 ULSD	CVS NO RD	1965	3	GAS / VAPOR	1/6 60FT S C GB-701 PSV-11 PRV
UNICRACKER- #250 ULSD	CVS NO RD	1968	1.5	GAS / VAPOR	1/6 50FT S C GB-701 PSV-23 PRV
UNICRACKER- #250 ULSD	CVS NO RD	1971	1.5	GAS / VAPOR	1/6 45FT S C GB-701 PSV-45 PRV
UNICRACKER- #250 ULSD	CVS NO RD	1976	1.5	GAS / VAPOR	1/6 35FT S C GB-701 PSV-22 PRV
UNICRACKER- #250 ULSD	CVS NO RD	1992	1.5	GAS / VAPOR	1/6 40FT S C GB-701 PSV-46 PRV
UNICRACKER- #250 ULSD	CVS NO RD	2119	0.75	GAS / VAPOR	1/7 8FT S C GB-701 N PRV
UNICRACKER- #250 ULSD	CVS NO RD	2415	1.5	LIGHT LIQUID	1/5 25FT NE T D-711 PRV PSV-1 PRV
UNICRACKER- #250 ULSD	CVS NO RD	2416	1.5	LIGHT LIQUID	1/5 25FT NE T D-711 PRV PSV-2 PRV
UNICRACKER- #250 ULSD	CVS NO RD	2445	4	GAS / VAPOR	T/6 SESD T D-711 PRV
UNICRACKER- #250 ULSD	CVS NO RD	2588	0.25	GAS / VAPOR	G/3 ESD AH AIT-281 PRV PSV-2800
UNICRACKER- #250 ULSD	CVS NO RD	2594	0.25	GAS / VAPOR	G/3 ESD AH AIT-281 PRV PSV-280A
UNICRACKER- #250 ULSD	CVS NO RD	3797	0.25	GAS / VAPOR	G/5 ESD AH AIT-281 PRV PSV-281A
UNICRACKER- #250 ULSD	CVS NO RD	50086	1.5	GAS / VAPOR	3/5 22FT NW E E-708 PRV PSV-3
UNICRACKER- #250 ULSD	CVS NO RD	50088	4	GAS / VAPOR	G/30 9FT E E E-703A PRV PSV-93
UNICRACKER- #250 ULSD	CVS NO RD	80867	8	GAS / VAPOR	T/7 SWSD T D-710 PRV PSV-15
UNICRACKER- #250 ULSD	CVS NO RD	84220	1.5	LIGHT LIQUID	2/1 4FT N V D-713 PRV PSV-25
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7467	1.5	GAS / VAPOR	G/8 NWSD V V-1 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7485	2	GAS / VAPOR	G/6 SSD V ME-103 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7510	2	GAS / VAPOR	G/6 12FT SE V ME-103 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7627	0.75	LIGHT LIQUID	1/9 20FT N E E-5 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7640	1	LIGHT LIQUID	1/9 30FT N E E-5 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7750	2	GAS / VAPOR	G/4 6FT S V V-22 PRV PSV-72

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7753	2	GAS / VAPOR	G/4 6FT S V V-24 PRV PSV-74
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7756	2	GAS / VAPOR	G/4 6FT S V V-26 PRV PSV-76
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7759	2	GAS / VAPOR	G/4 6FT S V V-28 PRV PSV-78
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7762	2	GAS / VAPOR	G/4 6FT S V V-30 PRV PSV-80
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7769	2	GAS / VAPOR	G/4 6FT N V V-29 PRV PSV-79
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7774	2	GAS / VAPOR	G/4 6FT N V V-27 PRV PSV-77
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7775	2	GAS / VAPOR	G/4 6FT N V V-25 PRV PSV-75
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7778	2	GAS / VAPOR	G/4 6FT N V V-23 PRV PSV-73
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7783	2	GAS / VAPOR	G/4 6FT N V V-21 PRV PSV-71
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7831	6	GAS / VAPOR	G/6 17FT NE V V-12 PRV PSV-101-1
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7883	6	GAS / VAPOR	T/5 CTR V V-8 PRV PSV-7
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7926	3	GAS / VAPOR	2/5 NESD FF E-7 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	7988	6	GAS / VAPOR	3/5 6FT N V V-4 PRV PSV-115
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	80849	4	GAS / VAPOR	1/12 8FT N C CM-1 110-PSV-100
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	8301	2	GAS / VAPOR	1/2 NSD V V-2 PRV
WEST BULK - #110 HYDROGEN PLANT	CVS NO RD	8333	3	GAS / VAPOR	T/4 3FT S V V-1 PRV
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	10103	0.75	LIGHT LIQUID	G/2 183FT SW H B-3A PRV PSV-220
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	10109	0.75	LIGHT LIQUID	G/2 186FT SW H B-3A PRV PSV-216
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	10130	1	LIGHT LIQUID	G/2 10FT E SUB STATION 8B PRV PSV-590
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9335	2	GAS / VAPOR	T/4 ESD V F-17 PRV PSV-154
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9385	2	GAS / VAPOR	G/6 ABV V F-39 PRV PSV-164
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9442	2	GAS / VAPOR	1/4 10FT SW C G-17C PRV PSV-311 PRV
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9472	2	LIGHT LIQUID	1/4 13FT SW C G-17B PRV PSV-211 PRV
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9501	3	GAS / VAPOR	1/7 8FT E E E-01B PRV PSV-179 PRV
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9508	3	GAS / VAPOR	1/4 13FT SW C G-17A PRV PSV-111 PRV
WEST BULK - #3 STM. POWER PLT.	CVS NO RD	9615	2	GAS / VAPOR	G/3 NSD V F-37 PRV PSV-946
WEST BULK - MARINE TERMINAL	CVS NO RD	16669	0.75	LIGHT LIQUID	G/5 SWSD TK TK-100 PRV PSV-6
WEST BULK - MARINE TERMINAL	CVS NO RD	34489	1.5	GAS / VAPOR	1/4 5FT W TCLR ME-6B PRV PSV-133
WEST BULK - MARINE TERMINAL	CVS NO RD	34543	1	GAS / VAPOR	1/4 4FT W TCLR ME-8B PRV PSV-136
WEST BULK - MARINE TERMINAL	CVS NO RD	34586	0.75	LIGHT LIQUID	1/4 49FT W TCLR 23ME-3 PRV PSV-6 LN BUTANE
WEST BULK - MARINE TERMINAL	CVS NO RD	34590	0.75	LIGHT LIQUID	1/3 49FT W TCLR 23ME-3 PRV PSV-7
WEST BULK - MARINE TERMINAL	CVS NO RD	34599	0.75	LIGHT LIQUID	1/6 40FT W TCLR 23ME-3 PRV PSV-12
WEST BULK - MARINE TERMINAL	CVS NO RD	34646	0.75	GAS / VAPOR	G/6 SSD D F-304 PRV PSV-8
WEST BULK - MARINE TERMINAL	CVS NO RD	34786	0.75	LIGHT LIQUID	G/6 7FT W P 23G-2 PRV PSV-10

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
WEST BULK - MARINE TERMINAL	CVS NO RD	34807	0.75	LIGHT LIQUID	G/6 7FT NW P 23G-2 PRV PSV-4
WEST BULK - MARINE TERMINAL	CVS NO RD	34832	0.75	LIGHT LIQUID	1/6 BTM TK F-302 PRV PSV-3
WEST BULK - MARINE TERMINAL	CVS NO RD	34876	0.75	LIGHT LIQUID	G/4 SWSD TK TK-100 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	34885	0.75	LIGHT LIQUID	G/5 SWSD TK TK-100 PRV PSV-7
WEST BULK - MARINE TERMINAL	CVS NO RD	34912	0.75	LIGHT LIQUID	G/7 NWSD P 20G-100 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	34933	1	LIGHT LIQUID	G/3 60FT E TK TK-531 PRV PSV-7-65
WEST BULK - MARINE TERMINAL	CVS NO RD	34937	1	LIGHT LIQUID	G/2 40FT E TK TK-531 PRV PSV-226
WEST BULK - MARINE TERMINAL	CVS NO RD	34942	2	GAS / VAPOR	G/2 11FT W TK TK-531 PRV PSV-746
WEST BULK - MARINE TERMINAL	CVS NO RD	50024	6	GAS / VAPOR	T/3 SWSD TK TK-302 PRV PSV-1
WEST BULK - MARINE TERMINAL	CVS NO RD	50025	1	GAS / VAPOR	T/3 SWSD TK TK-302 PRV PSV-1A
WEST BULK - MARINE TERMINAL	CVS NO RD	50028	1	GAS / VAPOR	T/3 SSD TK TK-302 PRV PSV-2A
WEST BULK - MARINE TERMINAL	CVS NO RD	50029	6	GAS / VAPOR	T/3 SSD TK TK-302 PRV PSV-2
WEST BULK - MARINE TERMINAL	CVS NO RD	80367	1.5	LIGHT LIQUID	1/4 NSD P G-16 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	83304	1	LIGHT LIQUID	G/1 14FT S P G-182 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	83305	1	LIGHT LIQUID	G/4 29FT SE P G-182 PRV PSV-118 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8374	0.75	LIGHT LIQUID	G/14 10FT SW P G-28 PRV PRV-81 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8376	1	LIGHT LIQUID	G/14 15FT SE P G-28 PRV RV-300 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8378	1	LIGHT LIQUID	G/14 16FT SE P G-28 PRV RV-307 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8380	1	LIGHT LIQUID	G/14 17FT SE P G-28 PRV RV-299 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8382	1	LIGHT LIQUID	G/14 18FT SE P G-28 PRV RV-304 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8384	1	LIGHT LIQUID	G/14 19FT SE P G-28 PRV RV-303 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8386	1	LIGHT LIQUID	G/14 25FT SE P G-28 PRV RV-308 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8388	1	LIGHT LIQUID	G/14 26FT SE P G-28 PRV RV-297 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8390	0.75	LIGHT LIQUID	G/14 30FT SE P G-28 PRV RV-694 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8392	0.75	LIGHT LIQUID	G/14 35FT SE P G-28 PRV RV-296 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8394	0.75	LIGHT LIQUID	G/14 40FT SE P G-28 PRV RV-695 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	8608	1.5	LIGHT LIQUID	G/4 ESD P G-15 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9017	1	LIGHT LIQUID	G/6 SSD TK TK-103 PRV PSV-610 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9029	1.5	LIGHT LIQUID	G/5 NESD P GM-2 PRV PSV-606 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9101	0.75	LIGHT LIQUID	G/5 19FT S P G-870 PRV PSV-96 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9117	0.75	LIGHT LIQUID	G/5 18FT S P G-870 PRV PSV-99 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9121	0.75	LIGHT LIQUID	G/7 22FT S P G-870 PRV PSV-88 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9132	0.75	LIGHT LIQUID	G/4 36FT S P G-181 W PRV PSV-130 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9182	0.75	LIGHT LIQUID	G/5 36FT S P G-181 E PRV PSV-128 PRV

Attachment J

Unit	Sub Type	Tag	Size	Service Type	Location Description
WEST BULK - MARINE TERMINAL	CVS NO RD	9188	1	LIGHT LIQUID	G/2 36FT S P G-181 PRV PSV-102 PRV
WEST BULK - MARINE TERMINAL	CVS NO RD	9223	1	LIGHT LIQUID	G/3 14FT S P G-182 PRV

Attachment K – Flare Construction

Flare	**Main Flare (S-296)**	**MP30 Flare (S-398)**
Flare Type	Elevated	Elevated
Type of Assist System	Steam	Steam
Emergency or Non-Emergency	Emergency (SU/SD, emergency)	Emergency (SU/SD, emergency)
Equipped with Flare Gas Recovery	Yes	Yes
Flare Height	250' – See Att. C	225' – See Att C
Pipe Diameter	5' – See Att C	4' – See Att C
Tip Diameter, ft		
Outside	5'	5.75'
Effective	5'	4.13'
Number of Pilots	4 – See Section 2.2.3.1	4 – See Section 2.2.3.2
Ignition System	Automatic	Automatic
Number of Steam Injection Nozzles	2 steam injection headers (2" & 6") and a Callidus BTZ-US upper steam flare tip.	2 steam injection headers (3" & 6") and a Callidus BTZ-IS3 multiple internal steam injection system.
Capacity [1] (i.e. Max Vent Gas Flow)	689 ton/hr	488 ton/hr
Smokeless Capacity (15 min avg) [2]	412,850 lb/hr	317,000 lb/hr
Maximum Supplemental Gas Flow	102 MSCFH	130 MSCFH
Minimum Total Steam Rate	4,000 lb/hr	2,500 lb/hr
Maximum Total Steam Rate	90,000 lb/hr	80,000 lb/hr
Date of Construction [3]	1970 approx , Tip Replaced 1996	2000
Location of Purge Gas Insertion	See Attachment B, Section titled "Main Flare Purge Gas Requirements" for details. See also Att C for placement on PFD.	See Attachment B, Section titled "MP-30 Flare Operation" for details. See also Att C for placement on PFD.

[1] Capacity provided is based on expected flow from total power failure. Flare system likely able to handle larger flow. Main design factor for flare tip diameter is gas exit velocity. Generally, flares are sized to permit a velocity of up to 0.5 Mach for short-term, peak, conditions with 0.2 Mach for normal conditions.

[2] Based on 3rd party flare tip vendor analysis.

[3] Per email correspondence on October 28, 2015 between an industry representative and the designated NSPS Ja Rule Contact, EPA has indicated that Confidential Business Information should not be included in Flare Management Plans. Consequently, the facility is not submitting the confidential flare tip schematic and P&IDs with this flare management plan. The flare tip schematic and P&IDs are available on site for EPA review.

Attachment N

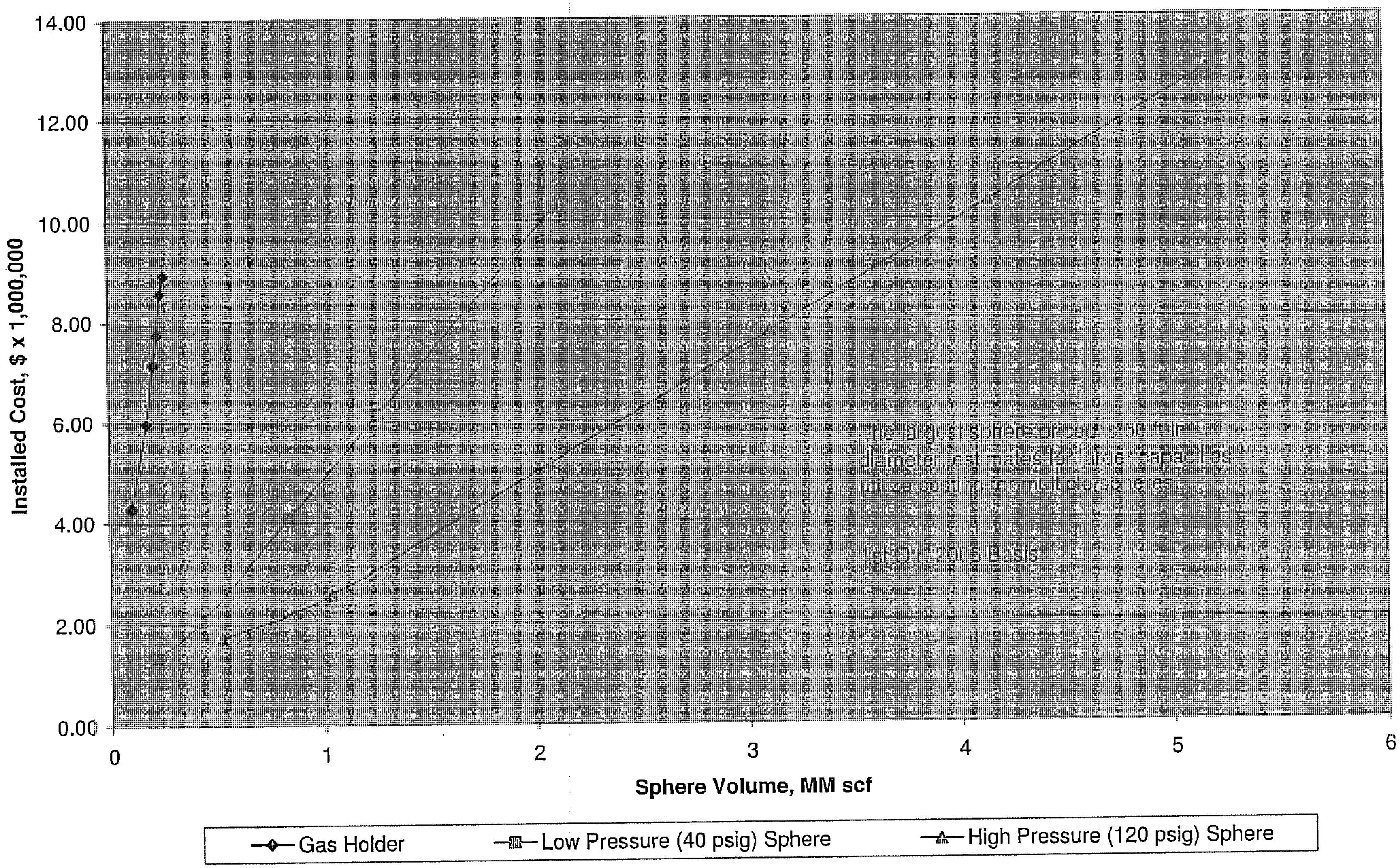
Cost Effectiveness Calculation Background Material

Attachment N

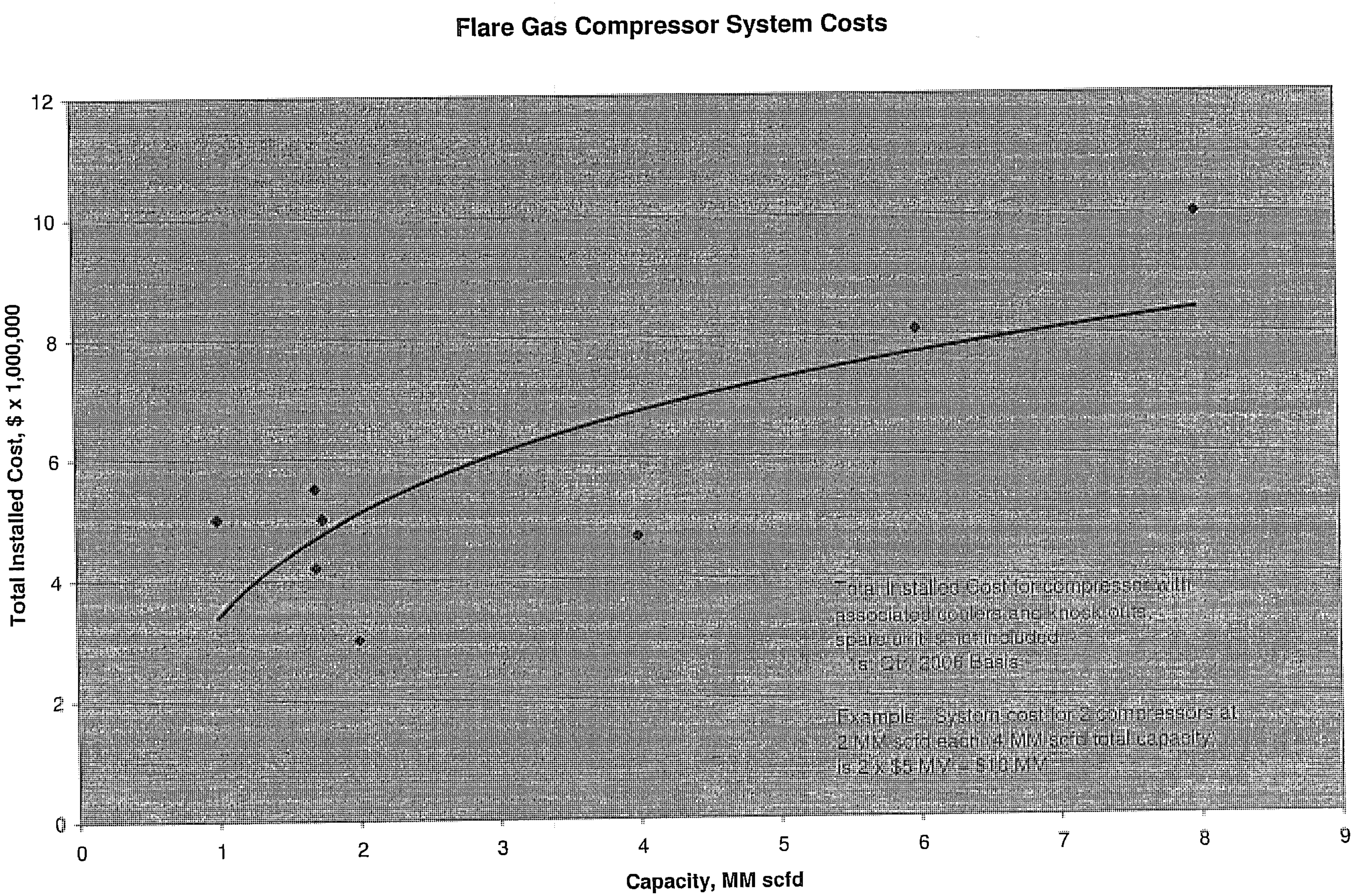
Cost Effectiveness Calculation Background Material

Cost Curves for Major Equipment

Flare Gas Storage Options

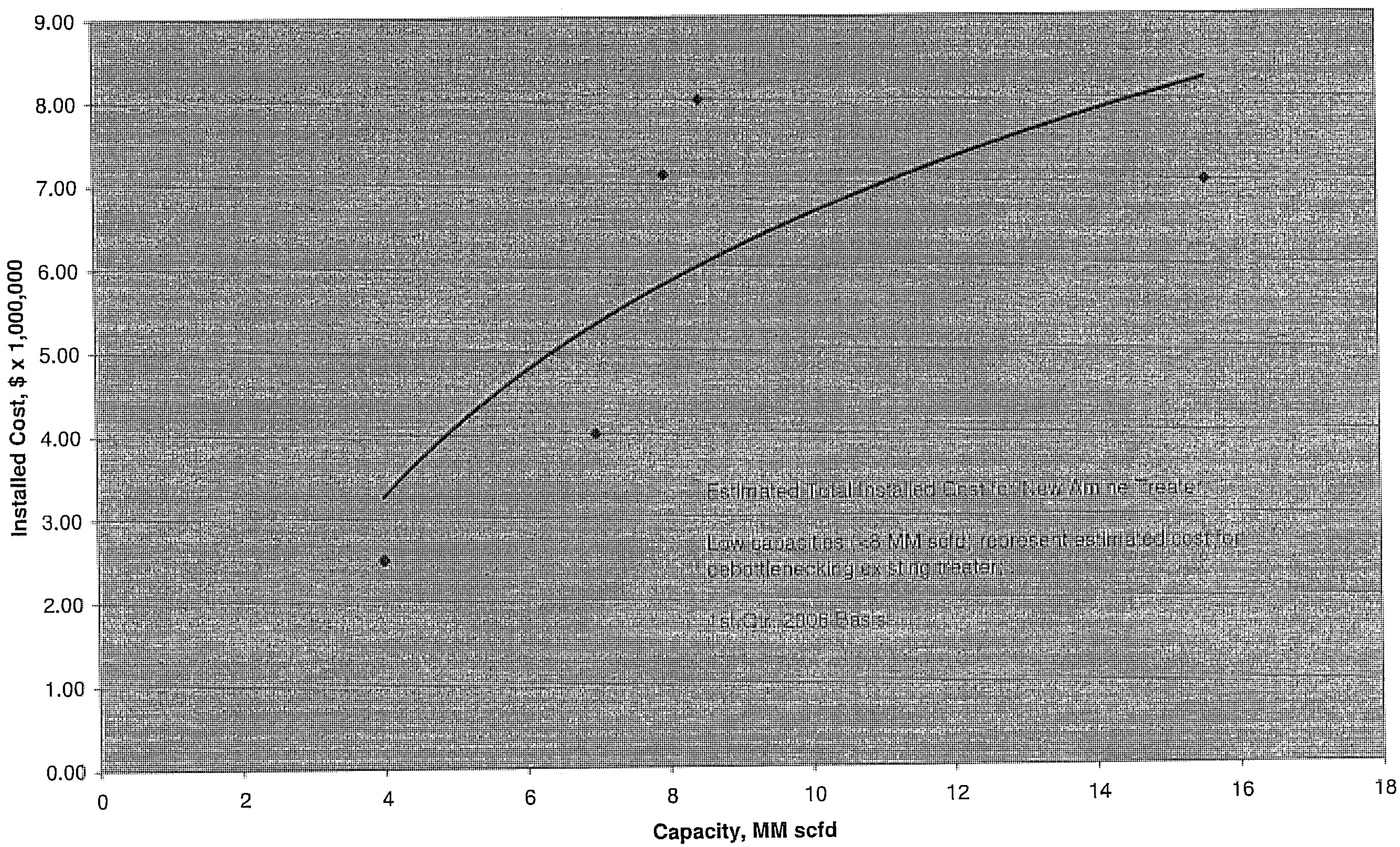


Confidential Attorney-Client Priviliged Work Document



Confidential Attorney-Client Privileged Document

Fuel Gas Amine Treater Costs



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Telephone Call Summary

By:	Tom Sudol	Date:	5/11/06
Talked with:	Ken Petro	Project number:	07230-018
From (company):	Chicago Bridge & Iron	Project name:	Flare Minimization Plan
Phone number:	302-325-8407	Subject:	Spherical Storage Tank Costs

Distribution:

Message

Ken Petro called to respond to my budgetary price quote request.

A 60-ft diameter sphere operating at 40 psig would cost $1,550,000. Another $60,000 can be added for painting, and another $200,000 can be added for the foundation (foundation was estimated based on the general locations of the refineries, and the earthquake zone that they are located in). This tank would be a Div. I tank. The total installed cost of this tank is $1,810,000.

A 60-ft diameter sphere operating at 120 psig would cost $2,100,000. The painting and foundation costs would remain the same, bringing the total installed cost of the tank to $2,360,000. This tank would be a Div. II tank.

All prices quoted over the phone are +/- 25%.

To stress relieve (heat treat) the spheres, costs would increase as follows:

40 psi sphere, 60 ft diameter
$1,790,000 installed cost (up from $1,550,000), not including:
$200,000 foundation (unchanged)
$60,000 painting (unchanged)

60 psi sphere, 60 ft diameter
$2,325,000 installed cost (up from $2,100,000), not including:
$200,000 foundation (unchanged)
$60,000 painting (unchanged)

Signature

Cost Effective & Emission Calculations for

Storage, Treatment, and Recovery Cases 1 – 4

Storage, Treatment, & Recovery Scenario - Emission Reduction & Cost Effective Analysis

Case	Estimated Potential Reductions (tons/yr)					Cost Effective Basis (tons)	Cost of Control ($)	Annualized Cost of Abatement System ($)	Cost Effectiveness Basis ($/ton)
	VOC	SO2	Nox	CO	PM				
1	-0.15	-0.62	-0.02	-0.19	*0.00*	-0.98	$ 3,250,000	$ 1,061,000	$ (1,084,092)
2	-1.12	-4.51	-0.13	-1.38	*-0.01*	-7.16	$ 7,500,000	$ 2,508,000	$ (350,420)
3	-1.57	-6.35	-0.19	-1.94	*-0.02*	-10.07	$ 23,400,000	$ 6,195,000	$ (615,476)
4	-2.02	-8.18	-0.24	-2.51	*-0.02*	-12.97	$ 23,400,000	$ 6,195,000	$ (477,509)

Cost/Benefit Analysis for Flare Minimization

Case: Installation of Small Compressor to Capture Brief Peak Loads
1.5 MMSCFD Compressor - Eliminate Brief Peak Loading (100% of 2005)

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levelized cash flow method"

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) / (Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Reduction in Annual Pollutant Emissions =
1,954 lb/yr emissions of POG, NOx, CO, & SO2
0.98 tons/yr

Total Capital Cost — $3,250,000

CRF = Capital Recovery Factor (to annualize capital cost)
CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$
i = interest rate, at 0.06
n = lifetime of abatement system, at 10 yrs
CRF = 0.1359

Utilities

Power
400 bhp for flare gas compressor
0.85 efficiency at design
351.1 kw
0.10 $/kw
8,760 operating hours per year
$307,528 /yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	65,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	65,000
Utilities (power)		307,528
Total		$437,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	52,000
Property Tax at	1 % of Total Capital Cost	32,500
Insurance at	1 % of Total Capital Cost	32,500
General and Admin. at	2 % of Total Capital Cost	65,000
Capital Recovery at CRF x Total Capital Cost		441,571
Total		$623,571

Annualized Cost of Abatement System = $1,061,000

Cost Effectiveness = $1,086,000 per ton

Case No.	1					
Case Title	Add Small 1.5 MMSCF/D Compressor					
Benefits Description	All small peak loading events (Att H - G503 Capacity Exceedance) to be eliminated. Emission basis is 2005 actual event. Rather than vent gas being routed to the flare, it will be captured and utilized as fuel.					
	Flow (MMSCF/yr)	POC (TPY)	SO2 (TPY)	Nox (TPY)	CO (TPY)	PM (TPY)
Baseline: Total Flow to Flare	58.46	9.59	39.75	2.19	11.90	0.32
Flow Captured, Routed to Htr	(0.946)	0.003	0.026	0.017	0.003	0.004
Remaining Flow to Flare	57.516	9.433	39.111	2.151	11.705	0.316
Total Emissions - Post Control		9.44	39.14	2.17	11.71	0.32
Emission Reduction	(0.98)	(0.15)	(0.62)	(0.02)	(0.19)	(0.00)

Total Pollutants

Emission Evaluation

Control Method	2005 Baseline Flaring Flare - Actual	Proposed Flow to Control		Baseline - Rerouted Flow Flare	Controlled at Heater Emissions Heater	Total Emissions	Emission Reduction
Total Volume to Flare (MMSCF/d)	0.25	0.003	0.074	0.158	0.003		
Total Volume to Flare (MMSCF/y)	58.462	0.946		57.516	0.946		
lb non-methane hydrocarbon (POC) to flare/scf flared gas [1]	0.0164	0.0164		0.0164	0.0164		
lb/yr non-methane hydrocarbon (POC) to flare	958,777	15,514		943,262	15,514		
Emissions from the Flare							
% Destruction of hydrocarbon in flare	98			98			
lb non-methane hydrocarbon (POC) emitted / scf flare gas	0.00033			0.00033			
lb sulfur dioxide (SO2) emission / scf flare gas	0.00136			0.00136			
POC: lb/yr non-methane hydrocarbon emissions from flare	19,176			18,865			
POC: ton/yr non-methane hydrocarbon emissions from flare	9.59			9.43			
SO2: lb/yr sulfur dioxide hydrocarbon emissions from flare	79,508			78,222			
SO2: ton/yr sulfur dioxide hydrocarbon emissions from flare	39.75			39.11			
NOX: Nox Emission Factor	0.068 lb/MMBtu						
Flare Gase Heating Value	1,100 Btu/scf						
lb/yr Nox Emissions from Flare	4,373			4,302			
tons/yr Nox from Flare	2.19			2.15			
CO Emission Factor	0.370 lb/MMBtu						
Flare Gase Heating Value	1,100 Btu/scf						
lb/yr CO Emissions from Flare	23,794			23,409			
tons/yr CO from Flare	11.90			11.70			
PM Emission Factor	0.01 lb/MMBtu per BAAQMD email 2/27/07						
lb/yr PM Emissions from Flare	643			633			
tons/yr PM from Flare	0.32			0.32			

Emissions from Heater						
% Destruction of hydrocarbon in heater	n/a	99.50%	n/a	99.50%		
lb non-methane hydrocarbon (POC) emitted heater / scf flare gas	n/a	0.0000055	n/a	0.0000055		
Total sulfur (TS) (ppmv) content of scrubbed fuel gas		325		325		
POC: lb/yr non-methane hydrocarbon emissions from heater	n/a	5	n/a	5		
POC: ton/yr non-methane hydrocarbon emissions from heater	n/a	0.00	n/a	0.00		
SO2: lb/yr sulfur dioxide emissions from heater		51.92		51.92		
SO2: ton/yr sulfur dioxide emissions from heater		0.03		0.03		
NOX: Nox Emission Factor				0.033 lb/MMBtu		
Flare Gase Heating Value				1,100 Btu/scf		
lb/yr Nox Emissions from Flare				34 lb/yr		
tons/yr Nox from Flare				0.02 tpy		
CO Emission Factor				100 ppmv		
lb/yr CO Emissions from Flare				6.99 lb/yr		
tons/yr CO from Flare				0.0035 tpy		
PM Emission Factor				7.60 lb/MMScf, AP-42		
lb/yr PM Emissions from Flare				7.19 lb/yr		
tons/yr PM from Flare				0.0036 tpy		
Emissions to the Atmosphere					**Total**	
POC: lb/yr	19,176		18,865	5	18,870	-305.08
POC: tpy	9.59		9.43	0	9.4	-0.15
SO2: lb/yr	79,508		78,222	52	78,274	-1,234.64
SO2: tpy	39.75		39.11	0	39.1	-0.62
NOX: lb/yr	4,373		4,302	34	4,337	-36.42
NOX: tpy	2.19		2.15	0.02	2.17	-0.02
CO: lb/yr	23,794		23,409	7	23,416	-378.03
CO: tpy	11.90		11.70	0.003	11.71	-0.19
PM: lb/yr	643.08		632.68	7.19	640	-3.22
PM: tpy	0.32		0.32	0.0036	0.320	0.00

[1] POC & SO2 levels based on historical sampling data.

Cost/Benefit Analysis for Flare Minimization

Case: Installation of Larger Compressor to Capture Brief Peak Loads & G-503 Maintenance
6.0 MMSCFD Compressor - Eliminate Brief Peak Loading & G-503 PM (100% of 2005)
Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"

Reduction in Annual Pollutant Emissions =
-11,475 lb/yr emissions of POG, NOx, CO, & SO2
-5.74 tons/yr

Total Capital Cost $7,500,000
CRF = Capital Recovery Factor (to annualize capital cost)
CRF = $[i\,(1+i)^n]/[(1+i)^n - 1]$
i = interest rate, at 0.06
n = lifetime of abatement system, at 10 yrs
CRF = 0.1359

Utilities
Power
1,000 bhp for flare gas compressor
0.85 efficiency at design
877.6 kw
0.10 $/kw
8,760 operating hours per year
$768,819 /yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	150,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	150,000
Utilities (power)		768,819
Total		$1,068,819

Indirect Costs		$/year
Overhead at	80 % of Labor costs	120,000
Property Tax at	1 % of Total Capital Cost	75,000
Insurance at	1 % of Total Capital Cost	75,000
General and Admin. at	2 % of Total Capital Cost	150,000
Capital Recovery at CRF x Total Capital Cost		1,019,010
Total		$1,439,010

Annualized Cost of Abatement System = $2,508,000

Cost Effectiveness = -$437,000 per ton

Case No.	2					
Case Title	Add larger 6 MMSCF/D compressor					
Benefits Description	Eliminate Brief Peak Loading (G-503 Capacity Exceedance) & G-503 PM (100% of 2005). Emission basis is 2005 actual event. Rather than vent gas being routed to the flare, it will be captured and utilized as fuel.					
	Flow (MMSCF/yr)	POC (TPY)	SO2 (TPY)	Nox (TPY)	CO (TPY)	PM (TPY)
Baseline: Total Flow to Flare	58.46	9.59	39.75	2.19	11.90	0.32
Flow Captured, Routed to Htr	(6.918)	0.019	0.190	0.126	0.026	0.026
Remaining Flow to Flare	51.544	8.453	35.050	1.928	10.489	0.283
Total Emissions - Post Control		8.47	35.24	2.05	10.51	0.31
Emission Reduction	(7.15)	(1.12)	(4.51)	(0.13)	(1.38)	(0.01)
		Total Pollutants				

	2005 Baseline Flaring		Proposed Flow to Control	Emission Evaluation: Baseline - Rerouted Flow	Emission Evaluation: Controlled at Heater Emissions	Total Emissions	Emission Reduction
Control Method	Flare - Actual			Flare	Heater		
Total Volume to Flare (MMSCF/d)	0.25		0.019	0.141	0.019		
Total Volume to Flare (MMSCF/y)	58.462		6.918	51.544	6.918		
lb non-methane hydrocarbon (POC) to flare/scf flared gas [1]	0.0164		0.0164	0.0164	0.0164		
lb/yr non-methane hydrocarbon (POC) to flare	958,777		113,455	845,322	113,455		
Emissions from the Flare							
% Destruction of hydrocarbon in flare	98			98			
lb non-methane hydrocarbon (POC) emitted / scf flare gas	0.00033			0.00033			
lb sulfur dioxide (SO2) emission / scf flare gas	0.00136			0.00136			
POC: lb/yr non-methane hydrocarbon emissions from flare	19,176			16,906			
POC: ton/yr non-methane hydrocarbon emissions from flare	9.59			8.45			
SO2: lb/yr sulfur dioxide hydrocarbon emissions from flare	79,508			70,100			
SO2: ton/yr sulfur dioxide hydrocarbon emissions from flare	39.75			35.05			
NOX: Nox Emission Factor	0.068	lb/MMBtu					
Flare Gase Heating Value	1,100	Btu/scf					
lb/yr Nox Emissions from Flare	4,373			3,855			
tons/yr Nox from Flare	2.19			1.93			
CO Emission Factor	0.370	lb/MMBtu					
Flare Gase Heating Value	1,100	Btu/scf					
lb/yr CO Emissions from Flare	23,794			20,978			
tons/yr CO from Flare	11.90			10.49			
PM Emission Factor	0.01	lb/MMBtu per BAAQMD email 2/27/07					
lb/yr PM Emissions from Flare	643			567			
tons/yr PM from Flare	0.32			0.28			

Emissions from Heater

% Destruction of hydrocarbon in heater	n/a	99.50%	n/a	99.50%	
lb non-methane hydrocarbon (POC) emitted heater / scf flare gas	n/a	0.0000055	n/a	0.0000055	
Total sulfur (TS) (ppmv) content of scrubbed fuel gas		325		325	
POC: lb/yr non-methane hydrocarbon emissions from heater	n/a	38	n/a	38	
POC: ton/yr non-methane hydrocarbon emissions from heater	n/a	0.02	n/a	0.02	
SO2: lb/yr sulfur dioxide emissions from heater		379.67		379.67	
SO2: ton/yr sulfur dioxide emissions from heater		0.19		0.19	
NOX: Nox Emission Factor				0.033	lb/MMBtu
Flare Gase Heating Value				1,100	Btu/scf
lb/yr Nox Emissions from Flare				251	lb/yr
tons/yr Nox from Flare				0.13	tpy
CO Emission Factor				100	ppmv
lb/yr CO Emissions from Flare				51.11	lb/yr
tons/yr CO from Flare				0.0256	tpy
PM Emission Factor				7.60	lb/MMScf, AP-42
lb/yr PM Emissions from Flare				52.58	lb/yr
tons/yr PM from Flare				0.0263	tpy

Emissions to the Atmosphere

				Total	
POC: lb/yr	19,176	16,906	38	16,944	-2,231.06
POC: tpy	9.59	8.45	0	8.5	-1.12
SO2: lb/yr	79,508	70,100	380	70,480	-9,028.81
SO2: tpy	39.75	35.05	0	35.2	-4.51
NOX: lb/yr	4,373	3,855	251	4,107	-266.34
NOX: tpy	2.19	1.93	0.13	2.05	-0.13
CO: lb/yr	23,794	20,978	51	21,030	-2,764.52
CO: tpy	11.90	10.49	0.026	10.51	-1.38
PM: lb/yr	643.08	566.98	52.58	620	-23.52
PM: tpy	0.32	0.28	0.0263	0.310	-0.01

Cost/Benefit Analysis for Flare Minimization

Case: Installation of Larger Compressor to Capture Brief Peak Loads & G-503 Maintenance

Range 1 - Conservative Estimate of Gasses to be Recovered

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levelized cash flow method"

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) / (Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
-20,098 lb/yr non-methane hydrocarbon emissions (POC) & SO2
-10.05 tons/yr

Total Capital Cost			$23,400,000
CRF = Capital Recovery Factor (to annualize capital cost)			
$CRF = [i (1 + i)^n] / [(1 + i)^n - 1]$			
i = interest rate, at	0.06		
n = lifetime of abatement system, at		10 yrs	
CRF =	0.1359		

Utilities

Power	1,000	bhp for flare gas compressor
	0.85	efficiency at design
	877.6	kw
	0.10	$/kw
	8,760	operating hours per year
	$768,819	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	468,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	468,000
Utilities (power)		768,819
Total		$1,704,819

Indirect Costs		$/year
Overhead at	80 % of Labor costs	374,400
Property Tax at	1 % of Total Capital Cost	234,000
Insurance at	1 % of Total Capital Cost	234,000
General and Admin. at	2 % of Total Capital Cost	468,000
Capital Recovery at CRF x Total Capital Cost		3,179,310
Total		$4,489,710

Annualized Cost of Abatement System = $6,195,000

Cost Effectiveness = -$616,000 per ton

Case No.	3					
Case Title	Add compressor and storage vessel					
Benefits Description	Eliminate Brief Peak Loading (G-503 Capacity Exceedance), G-503 PM (100% of 2005) portion of maintenance & some emergency events to be eliminated (5 - 10%). Emission basis is 2005 actual event. Rather than vent gas being routed to the flare, it will be captured and utilized as fuel.					
	Flow (MMSCF/yr)	POC (TPY)	SO2 (TPY)	Nox (TPY)	CO (TPY)	PM (TPY)
Baseline: Total Flow to Flare	58.46	9.59	39.75	2.19	11.90	0.32
Flow Captured, Routed to Htr	(9.729)	0.027	0.267	0.177	0.036	0.037
Remaining Flow to Flare	48.733	7.992	33.138	1.823	9.917	0.268
Total Emissions - Post Control		8.02	33.41	2.00	9.95	0.31
Emission Reduction	(10.05)	(1.57)	(6.35)	(0.19)	(1.94)	(0.02)

Total Pollutants

	2005 Baseline Flaring		Proposed Flow to Control		Emission Evaluation Baseline - Rerouted Flow	Emission Evaluation Controlled at Heater Emissions	Total Emissions	Emission Reduction
Control Method	Flare - Actual				Flare	Heater		
Total Volume to Flare (MMSCF/d)	0.25		0.027	0.074	0.134	0.027		
Total Volume to Flare (MMSCF/y)	58.462		9.73		48.733	9.729		
lb non-methane hydrocarbon (POC) to flare/scf flared gas [1]	0.0164		0.0164		0.0164	0.0164		
lb/yr non-methane hydrocarbon (POC) to flare	958,777		159,557		799,220	159,557		
Emissions from the Flare								
% Destruction of hydrocarbon in flare	98				98			
lb non-methane hydrocarbon (POC) emitted / scf flare gas	0.00033				0.00033			
lb sulfur dioxide (SO2) emission / scf flare gas	0.00136				0.00136			
POC: lb/yr non-methane hydrocarbon emissions from flare	19,176				15,984			
POC: ton/yr non-methane hydrocarbon emissions from flare	9.59				7.99			
SO2: lb/yr sulfur dioxide hydrocarbon emissions from flare	79,508				66,277			
SO2: ton/yr sulfur dioxide hydrocarbon emissions from flare	39.75				33.14			
NOX: Nox Emission Factor	0.068	lb/MMBtu						
Flare Gase Heating Value	1,100	Btu/scf						
lb/yr Nox Emissions from Flare	4,373				3,645			
tons/yr Nox from Flare	2.19				1.82			
CO Emission Factor	0.370	lb/MMBtu						
Flare Gase Heating Value	1,100	Btu/scf						
lb/yr CO Emissions from Flare	23,794				19,834			
tons/yr CO from Flare	11.90				9.92			
PM Emission Factor	0.01	lb/MMBtu per BAAQMD email 2/27/07						
lb/yr PM Emissions from Flare	643				536			
tons/yr PM from Flare	0.32				0.27			

Emissions from Heater						
% Destruction of hydrocarbon in heater	n/a	99.50%	n/a	99.50%		
lb non-methane hydrocarbon (POC) emitted heater / scf flare gas	n/a	0.0000055	n/a	0.0000055		
Total sulfur (TS) (ppmv) content of scrubbed fuel gas		325		325		
POC: lb/yr non-methane hydrocarbon emissions from heater	n/a	54	n/a	54		
POC: ton/yr non-methane hydrocarbon emissions from heater	n/a	0.03	n/a	0.03		
SO2: lb/yr sulfur dioxide emissions from heater		533.94		533.94		
SO2: ton/yr sulfur dioxide emissions from heater		0.27		0.27		
NOX: Nox Emission Factor				0.033	lb/MMBtu	
Flare Gase Heating Value				1,100	Btu/scf	
lb/yr Nox Emissions from Flare				353	lb/yr	
tons/yr Nox from Flare				0.18	tpy	
CO Emission Factor				100	ppmv	
lb/yr CO Emissions from Flare				71.88	lb/yr	
tons/yr CO from Flare				0.0359	tpy	
PM Emission Factor				7.60	lb/MMScf, AP-42	
lb/yr PM Emissions from Flare				73.94	lb/yr	
tons/yr PM from Flare				0.0370	tpy	
Emissions to the Atmosphere					**Total**	
POC: lb/yr	19,176		15,984	54	16,038	-3,137.63
POC: tpy	9.59		7.99	0	8.0	-1.57
SO2: lb/yr	79,508		66,277	534	66,811	-12,697.62
SO2: tpy	39.75		33.14	0	33.4	-6.35
NOX: lb/yr	4,373		3,645	353	3,998	-374.57
NOX: tpy	2.19		1.82	0.18	2.00	-0.19
CO: lb/yr	23,794		19,834	72	19,906	-3,887.86
CO: tpy	11.90		9.92	0.036	9.95	-1.94
PM: lb/yr	643.08		536.06	73.94	610	-33.08
PM: tpy	0.32		0.27	0.0370	0.305	-0.02

Cost/Benefit Analysis for Flare Minimization

Case: Installation of High Pressure Spheres, Compressor, & Amine Treatment
Range 2 - More Aggressive Estimate of Gasses to be Recovered

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT using the "levelized cash flow method"

Cost Effectiveness = (Annualized Cost of Abatement System (\$/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Reduction in Annual Pollutant Emissions =
-25,905 lb/yr non-methane hydrocarbon emissions (POC) & SO2
-12.95 tons/yr

Total Capital Cost			\$23,400,000
CRF = Capital Recovery Factor (to annualize capital cost)			
CRF = $[i\,(1 + i)^n] / [(1 + i)^n - 1]$			
i = interest rate, at	0.06		
n = lifetime of abatement system, at		10 yrs	
CRF =	0.1359		

Utilities

Power	1,000	bhp for flare gas compressor
	0.85	efficiency at design
	877.6	kw
	0.10	\$/kw
	8,760	operating hours per year
	\$768,819	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		\$/year
Labor	2 % of capital cost	468,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	468,000
Utilities (power)		768,819
Total		\$1,704,819

Indirect Costs		\$/year
Overhead at	80 % of Labor costs	374,400
Property Tax at	1 % of Total Capital Cost	234,000
Insurance at	1 % of Total Capital Cost	234,000
General and Admin. at	2 % of Total Capital Cost	468,000
Capital Recovery at CRF x Total Capital Cost		3,179,310
Total		\$4,489,710

Annualized Cost of Abatement System = \$6,195,000

Cost Effectiveness = -\$478,000 per ton

Case No.	4					
Case Title	Add compressor and storage vessel					
Benefits Description	Eliminate Brief Peak Loading (G-503 Capability Exceedance), G-503 PM (100% of 2005), portion of maintenance & some emergency events to be eliminated (10 - 30%). Emission basis is 2005 actual event. Rather than vent gas being routed to the flare, it					
	Flow (MMSCF/yr)	POC (TPY)	SO2 (TPY)	Nox (TPY)	CO (TPY)	PM (TPY)
Baseline: Total Flow to Flare	58.46	9.59	39.75	2.19	11.90	0.32
Flow Captured, Routed to Htr	(12.540)	0.034	0.344	0.228	0.046	0.048
Remaining Flow to Flare	45.922	7.531	31.227	1.717	9.345	0.253
Total Emissions - Post Control		7.57	31.57	1.95	9.39	0.30
Emission Reduction	(12.95)	(2.02)	(8.18)	(0.24)	(2.51)	(0.02)

Total Pollutants

	2005 Baseline Flaring		Proposed Flow to Control		Emission Evaluation Baseline - Rerouted Flow	Controlled at Heater Emissions	Total Emissions	Emission Reduction
Control Method	Flare - Actual				Flare	Heater		
Total Volume to Flare (MMSCF/d)	0.25		0.034	0.074	0.126	0.034		
Total Volume to Flare (MMSCF/y)	58.462		12.54		45.922	12.540		
lb non-methane hydrocarbon (POC) to flare/scf flared gas [1]	0.0164		0.0164		0.0164	0.0164		
lb/yr non-methane hydrocarbon (POC) to flare	958,777		205,658		753,119	205,658		
Emissions from the Flare								
% Destruction of hydrocarbon in flare	98				98			
lb non-methane hydrocarbon (POC) emitted / scf flare gas	0.00033				0.00033			
lb sulfur dioxide (SO2) emission / scf flare gas	0.00136				0.00136			
POC: lb/yr non-methane hydrocarbon emissions from flare	19,176				15,062			
POC: ton/yr non-methane hydrocarbon emissions from flare	9.59				7.53			
SO2: lb/yr sulfur dioxide hydrocarbon emissions from flare	79,508				62,454			
SO2: ton/yr sulfur dioxide hydrocarbon emissions from flare	39.75				31.23			
NOX: Nox Emission Factor	0.068	lb/MMBtu						
Flare Gase Heating Value	1,100	Btu/scf						
lb/yr Nox Emissions from Flare	4,373				3,435			
tons/yr Nox from Flare	2.19				1.72			
CO Emission Factor	0.370	lb/MMBtu						
Flare Gase Heating Value	1,100	Btu/scf						
lb/yr CO Emissions from Flare	23,794				18,690			
tons/yr CO from Flare	11.90				9.35			
PM Emission Factor	0.01	lb/MMBtu per BAAQMD email 2/27/07						
lb/yr PM Emissions from Flare	643				505			
tons/yr PM from Flare	0.32				0.25			

Emissions from Heater							
% Destruction of hydrocarbon in heater	n/a	99.50%	n/a	99.50%			
lb non-methane hydrocarbon (POC) emitted heater / scf flare gas	n/a	0.0000055	n/a	0.0000055			
Total sulfur (TS) (ppmv) content of scrubbed fuel gas		325		325			
POC: lb/yr non-methane hydrocarbon emissions from heater	n/a	69	n/a	69			
POC: ton/yr non-methane hydrocarbon emissions from heater	n/a	0.03	n/a	0.03			
SO2: lb/yr sulfur dioxide emissions from heater		688.22		688.22			
SO2: ton/yr sulfur dioxide emissions from heater		0.34		0.34			
NOX: Nox Emission Factor				0.033	lb/MMBtu		
Flare Gase Heating Value				1,100	Btu/scf		
lb/yr Nox Emissions from Flare				455	lb/yr		
tons/yr Nox from Flare				0.23	tpy		
CO Emission Factor				100	ppmv		
lb/yr CO Emissions from Flare				92.64	lb/yr		
tons/yr CO from Flare				0.0463	tpy		
PM Emission Factor				7.60	lb/MMScf, AP-42		
lb/yr PM Emissions from Flare				95.30	lb/yr		
tons/yr PM from Flare				0.0477	tpy		
Emissions to the Atmosphere						**Total**	
POC: lb/yr	19,176		15,062	69		15,131	-4,044.19
POC: tpy	9.59		7.53	0		7.6	-2.02
SO2: lb/yr	79,508		62,454	688		63,142	-16,366.35
SO2: tpy	39.75		31.23	0		31.6	-8.18
NOX: lb/yr	4,373		3,435	455		3,890	-482.79
NOX: tpy	2.19		1.72	0.23		1.95	-0.24
CO: lb/yr	23,794		18,690	93		18,783	-5,011.19
CO: tpy	11.90		9.35	0.046		9.39	-2.51
PM: lb/yr	643.08		505.14	95.30		600	-42.64
PM: tpy	0.32		0.25	0.0477		0.300	-0.02

Attachment O

Document Revision Log

Revision No.	Revision Date	Revision Author (Name, Company)	Reason for Revision	Requires Re-Submission to USEPA? (Re:Section 1.5)
0		J. Ahlskog	Initial FMP per BAAQMD 12-12 (ESDR-319-06)	n/a
0-3	Various Years (Annually)	Various Authors See past submittals	Annual FMP updates to BAAQMD	n/a
4	7/16/18	J. Ahlskog	Annual FMP update and installation of new Liquid Ring Flare Gas Recovery Compressor (ESDR-313-08)	n/a
5-16	Various Years (Annually)	Various Authors (See past submittals)	Annual FMP updates to BAAQMD	n/a
16	10/1/18	J. Ahlskog	Annual FMP update to BAAQMD (ESDR-273-18)	n/a
17	1/29/19	J. Ahlskog	Incorporation of EPA RSR requirements and corresponding compliance items across various sections of the FMP for all applicable flares. (ESDR-40-19)	Yes
18	10/1/19	J. Ahlskog	Annual FMP update to BAAQMD	n/a
19	10/1/20	J. Ahlskog	Annual FMP update to BAAQMD	n/a

ATTACHMENT C

Cerulogy Report

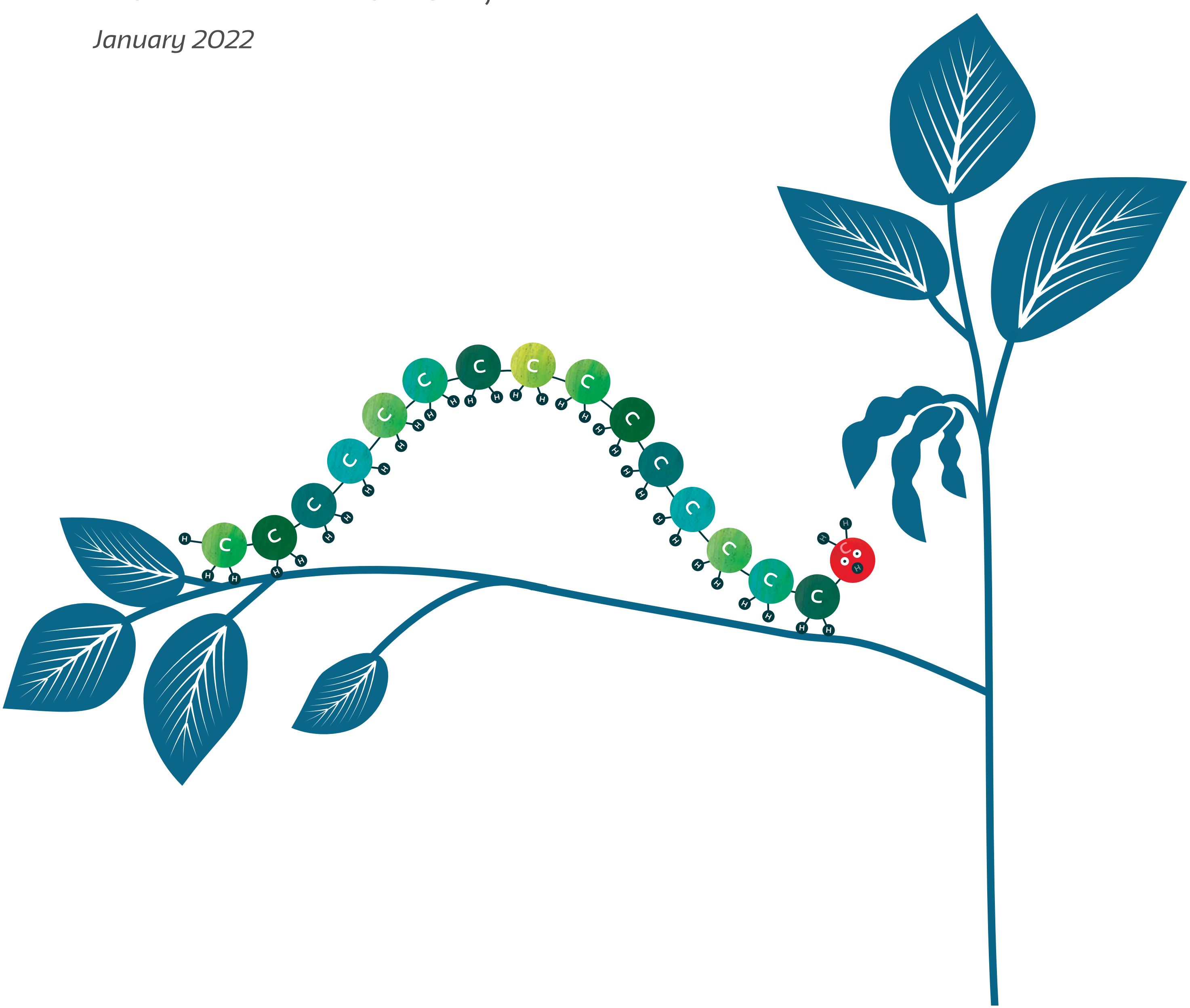
Cerulogy

Animal, vegetable or mineral (oil)?

Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States

Dr Chris Malins and Dr Cato Sandford

January 2022



Acknowledgements

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Summary

The production of renewable diesel by hydrotreating oils and fats has expanded rapidly around the world over the past decade. Unlike conventional biodiesel, renewable diesel is chemically similar enough to fossil diesel that it can be used in existing diesel engines with no blend limit. The process can produce renewable jet fuel as a co-product with minor modifications. The United States currently supports renewable diesel supply through the federal Renewable Fuel Standard, a biomass-based diesel blenders tax credit, and state level policies such as the California Low Carbon Fuel Standard and Oregon Clean Fuels Program. Based on recent credit values under these programs, this stack of policy support could be worth $4 per gallon for waste-oil-based renewable diesel supplied in California. The U.S. currently has about 800 million gallons of renewable diesel production capacity, and in 2020 produced about 500 million gallons.

The generous policy environment for renewable diesel has inspired a cascade of announcements of new projects, including new standalone facilities, conversions of existing refinery units and co-processing with fossil fuels at existing refineries. The Energy Information Administration reports that if all of these announced plans come to fruition renewable diesel production capacity in the U.S. would increase fivefold by 2024, from just under 1 billion gallon a year to more than 5 billion gallons per year (Figure 1). Running all of those potential facilities at full capacity would create 17 million metric tons of additional demand for oils and fats.

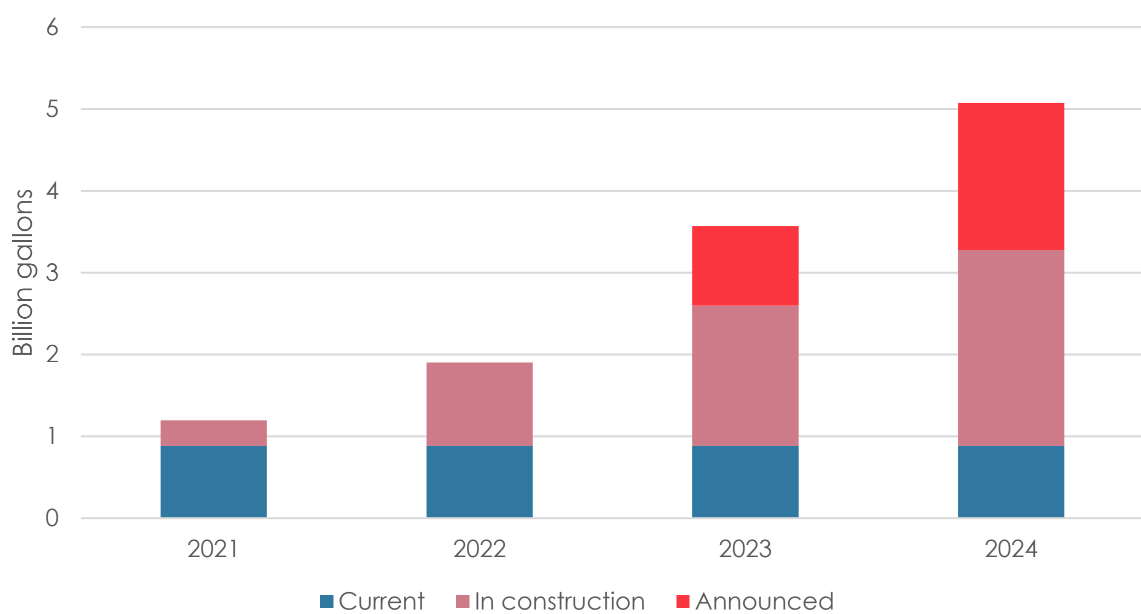

Figure 1. Announced renewable diesel production capacity expansion

Source: U.S. EIA (2021h)

If this capacity expansion could be delivered, it would represent a massive shift in the U.S. biofuel industry. Already the growth of renewable diesel production is impacting feedstock markets, with many analysts identifying growth in renewable diesel as a factor contributing to recent record soy oil prices. It is difficult to see how the millions of metric tons of vegetable oil that would be needed to supply a 5 billion gallons a year industry could be delivered. Predicted increases in domestic soy oil production could support perhaps another 300 million gallons of production, and increased utilization of waste and residual oils another 150 million gallons. Beyond this, increasing production would mean either dramatic unforeseen expansion of domestic soy and canola area, dramatic increases in canola and palm oil imports, or massive displacement of feedstock from other uses (or a combination of the three). Domestic biodiesel production is likely to be strongly impacted, with waste oils and fats in particular diverted to renewable diesel production for supply to the West Coast.

In practice, it seems highly unlikely that the full announced capacity expansion will be delivered. Limits on feedstock availability and limits on the support available for renewable diesel production from the RFS and other policies mean that the market will not support a 5 billion gallons industry as soon as 2024 (if ever). We expect that the next five years will see some projects delayed or cancelled, and some running far below nameplate capacity.

Even if only a half or a third of the announced capacity is delivered it still represents a massive increase in feedstock demand. There is a high risk that increased U.S. renewable diesel production will indirectly drive expansion of palm oil in Southeast Asia, where the palm oil industry is still endemically associated with deforestation and peat destruction. Consuming millions of metric tons of additional vegetable oil could cause tens of thousands of hectares of deforestation.

In setting recent volume mandates for the RFS, the EPA has stated that it is reluctant to mandate excessive growth in advanced biofuel requirements because of the risk that delivering more and more biomass-based diesel could cause market distortions and lead to CO_2 emissions from land use change. The current ramping up of the renewable diesel industry is an attempt to deliver that excessive growth, and there seems to be a very great risk that those undesirable market distortions will be realized. For states with low carbon fuel standards and similar programs, there is a question to be answered about whether unlimited growth in local renewable diesel supply is the best way to deliver on climate goals. If a major outcome of these policies is to suck in resources that would otherwise be supplied as biodiesel elsewhere, and thereby undermine the existing biodiesel business, that has little net climate benefit. Similarly, if the rapidity of vegetable oil demand increases leads to social damage through high food prices and to ILUC emissions as oil palm expands to compensate, that also will have little net climate benefit. It may be appropriate for state programs to consider limiting the contribution from renewable diesel.

More generally, the growth in vegetable oil hydrotreating as a biofuel pathway risks distracting investment from cellulosic biofuel technologies that are still not in wide operation at commercial scale, but that in the long-term could be more scalable, more sustainable, and cheaper.

Contents

1. Introduction

When the Renewable Fuel Standard (RFS) was first introduced in 2010, two types of biofuel dominated the U.S. and global markets – ethanol (used in gasoline engines) and fatty acid methyl ester (FAME) biodiesel (used in diesel engines). Both of these fuels are subject to blend limits, generally up to 10% ethanol by volume in gasoline and up to 5% biodiesel by volume in diesel. More recently a third technological pathway has been commercialized, with global production of 'renewable diesel', also referred to as hydrotreated vegetable oil (HVO), reaching about 7.5 billion liters in 2020 REN 21 (2021). Like biodiesel, renewable diesel substitutes fossil diesel fuel in the transport fuel supply, but unlike biodiesel renewable diesel is chemically similar enough to fossil diesel that there is no limit on the amount that may be blended without damaging vehicles. Renewable diesel relies on the same feedstock base as biodiesel – vegetable oils, including waste oils, and animal fats (henceforth "oils and fats"). It is therefore associated with the same sustainability challenges as biodiesel, such as the risks of driving indirect land use change (Malins et al., 2014) and putting upward pressure on food prices (Malins, 2017a). The main oils and fats used as feedstocks for biomass-based diesel supplied to the U.S. are soy oil, canola oil, distillers' corn oil (DCO)[1], used cooking oil (UCO)[2] and animal fats[3].

Renewable diesel is produced by treating oils and fats with hydrogen to remove oxygen and output hydrocarbon molecules. Renewable diesel may be produced at two types of facility. It can be produced at standalone oil and fat hydrotreating facilities, or it can be co-processed with petroleum at existing oil refineries. In the first case, the output is an entirely renewable fuel. In the second case, only some fraction of the output fuel may be treated as renewable.

To date, the vast majority of oil and fat hydrotreating capacity has been directed towards production of on-road diesel substitutes. In the coming decade, however, there is likely to be an increasing focus on alternative aviation fuel production. The International Civil Aviation Organisation is introducing the CORSIA emission offsetting system, under which alternative fuels use may contribute to airline obligations (ICCT, 2017); the Biden administration in the U.S. has declared a "Sustainable Aviation Fuel Grand Challenge" (The White House, 2021) to support the deployment of increased volumes of alternative aviation fuel; and the European Commission has proposed a mandate for aviation alternative fuel use in its ReFuelEU policy (European Commission, 2021). Hydrotreated oils and fats for aviation applications are often referred to as 'HEFA' (hydroprocessed esters and fatty acids). The process for renewable jet fuel production from oil and fat feedstocks is essentially the same process as for renewable diesel production (in practice, renewable jet fuel production generally requires fractionating and where necessary upgrading the output from hydrotreating facilities so that renewable jet fuel may be produced alongside renewable diesel).

This report provides an overview of the state of the renewable diesel market in the United States. It reviews the support available for renewable diesel under alternative fuel support policies and current and planned renewable diesel production capacity. It considers the

1 Distillers' corn oil is oil recovered from corn after fermentation for ethanol production and is not considered fit for human consumption.

2 Also referred to as yellow grease.

3 Including tallow from cattle, white grease from hogs and poultry oil.

implications of renewable diesel capacity growth for oil and fat markets and for the existing biodiesel industry, and it reviews the potential environmental impacts of increased renewable diesel production.

2. Policy support for renewable diesel

Renewable diesel costs more to produce than conventional fossil diesel, and therefore policy support is necessary to make renewable diesel production commercially viable. The most important U.S. policy instruments for renewable diesel producers are the Renewable Fuel Standard, the biomass-based diesel blenders tax credit, and state level incentives for decarbonizing transportation fuel such as the California Low Carbon Fuel Standard and the Oregon Clean Fuels Program. Even if renewable diesel production capacity grows very rapidly, the actual quantity of renewable diesel or jet fuel that gets supplied will be determined in large part by the level of regulatory support available.

2.1. Renewable Fuel Standard (RFS)

The RFS mandates fuel suppliers in the U.S. to supply minimum quantities of renewable fuels alongside the supply of petroleum fuels. The RFS is divided into several tiers with their own mandated supply levels. The mandates which are relevant to hydrotreated renewable diesel are:

1. The biomass-based diesel mandate, which is a mandate for supplying diesel-substitute fuels that deliver a reportable GHG emission saving of at least 50%. It is met by supplying biodiesel and renewable diesel, and is a sub-category of the advanced fuel mandate.

2. Advanced fuel mandate, which is a mandate for supplying fuels that are not produced from corn and that deliver a reportable GHG emission saving of at least 50%. It is met mainly with biomass-based diesel, renewable natural gas, and non-corn ethanol, and is a sub-category of the renewable fuel mandate.

3. Renewable fuel mandate, which is a mandate for any renewable fuels that can deliver a reportable GHG emission saving of at least 20% or are produced in facilities that had started construction by the end of 2007 ("grandfathering"). It is met by the supply of fuels covered by the advanced mandate plus corn ethanol and any other biofuels (such as biomass-based diesel from palm oil) that do not qualify as advanced but meet the standard to be counted as renewable.

The RFS works through the award of renewable identification numbers (RINs) for the production or import of biofuels, and different types of RIN are awarded to different types of biofuel. The relevant RIN codes for renewable diesel are D4, D5 and D6. D4 biomass-based diesel RINs are awarded to renewable diesel that meets the minimum GHG reduction requirement for advanced biofuels and is not co-processed with fossil petroleum. D5 advanced RINs are awarded to renewable diesel that meets the minimum GHG reduction requirement for advanced biofuels but is co-processed with fossil petroleum. D6 renewable RINs are awarded to renewable diesel that does not meet the minimum GHG requirement for advanced biofuels but that either meets a 20% GHG reduction or can be supplied under the grandfathering provision.

The supply of biomass-based diesel in the U.S. has historically been primarily driven by the advanced biofuel mandate. This is illustrated in Figure 2, where it can be seen that in general the generation of RINs for biomass-based diesel fuels has closely tracked the advanced fuel mandate. The above-mandate generation of biomass-based diesel RINs in 2016 may reflect the fact that the biomass-based diesel blender tax credit was approved in advance for that year, whereas in most other years it has only been activated retrospectively (see next section).

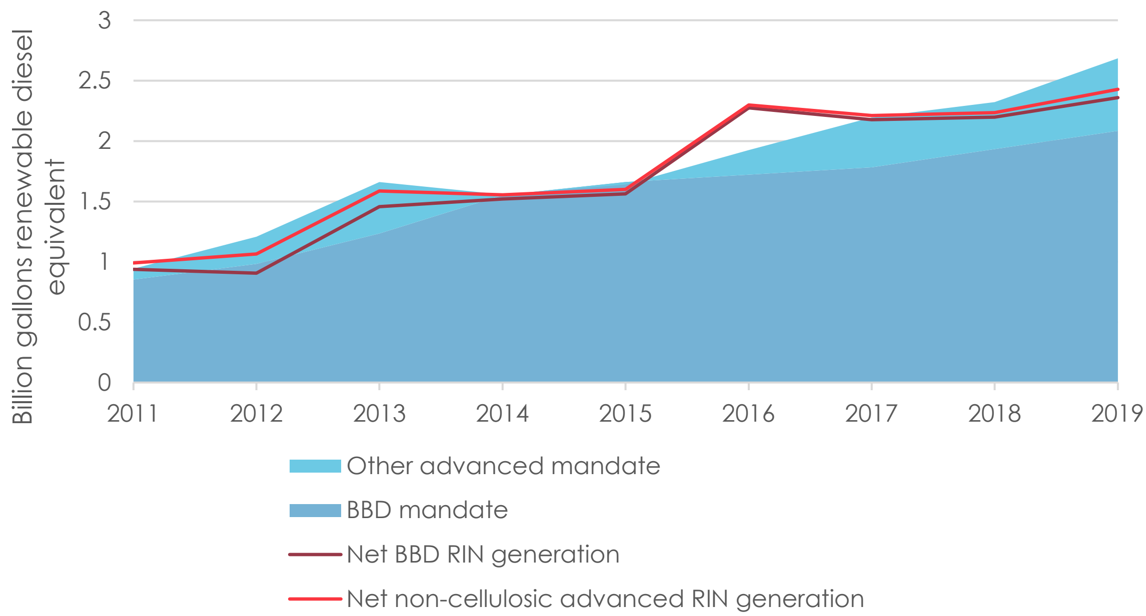

Figure 2. Renewable volume obligations and net* RIN generation for biomass-based diesel and for non-cellulosic non-biomass-based-diesel advanced fuels**

Source: U.S. EPA (2021b), U.S. EIA (2021e)

**Here net RIN generation is the number of D4 and D5 RINs generated by biomass-based diesel and all advanced fuels, minus the number of RINs presumed retired for the volume of biomass-based diesel exported from the U.S. in each year according to U.S. EIA (2021e).*

***The biomass-based diesel and cellulosic fuel mandates are nested within the advanced fuels mandate; here we show the remnant obligation that may be met with other advanced fuels or with additional cellulosic fuel or biomass-based diesel.*

If the advanced biofuel mandate of the RFS remains the main determinant of biomass-based diesel supply in future years, then the prospects for utilization of new renewable diesel capacity will depend on the level of future mandates. A proposed rule setting the 2022 biomass-based diesel standard and the 2020, 2021 and 2022 advanced biofuel standard was released by the EPA in December 2021 (U.S. EPA, 2021a). The proposed mandates are shown in Table 1. The non-cellulosic advanced fuel mandate for 2022 is set at the statutory minimum level of 2.9 billion gallons renewable diesel equivalent (RDE; 5 billion gallons ethanol equivalent), of which at least 2.4 billion gallons RDE must be biomass-based diesel.

Table 1. Proposed RFS volume mandates to 2022, billion gallons RDE

	2020	2021	2022
Non-cellulosic advanced biofuels	2.4	2.7	2.9
Biomass-based diesel*	2.1	2.1	2.4
Other advanced fuel	0.3	0.6	0.5

Source: U.S. EPA (2021a)

**Biomass based diesel mandates for 2020 and 2021 were already set*

Given that biomass-based diesel has historically made a large contribution to the remnant of the advanced fuel obligation and that the U.S. Congress has extended the biomass-based diesel tax credit to 2022, it is reasonable to assume that most or all of the 500-million-gallon RDE increase in mandated advanced fuel volume from 2020 to 2022 will be biomass-based diesel – but how much of this could be supplied as renewable diesel?

As shown in Figure 3, since 2016 increases in the overall biomass-based diesel supply have been delivered by increasing the supply of renewable diesel, with a downward trend in biodiesel supply volumes. Given this existing trend and the ongoing capacity expansions discussed later in this report, it seems likely that most or all growth in advanced biofuel supply to 2022 will be renewable diesel.

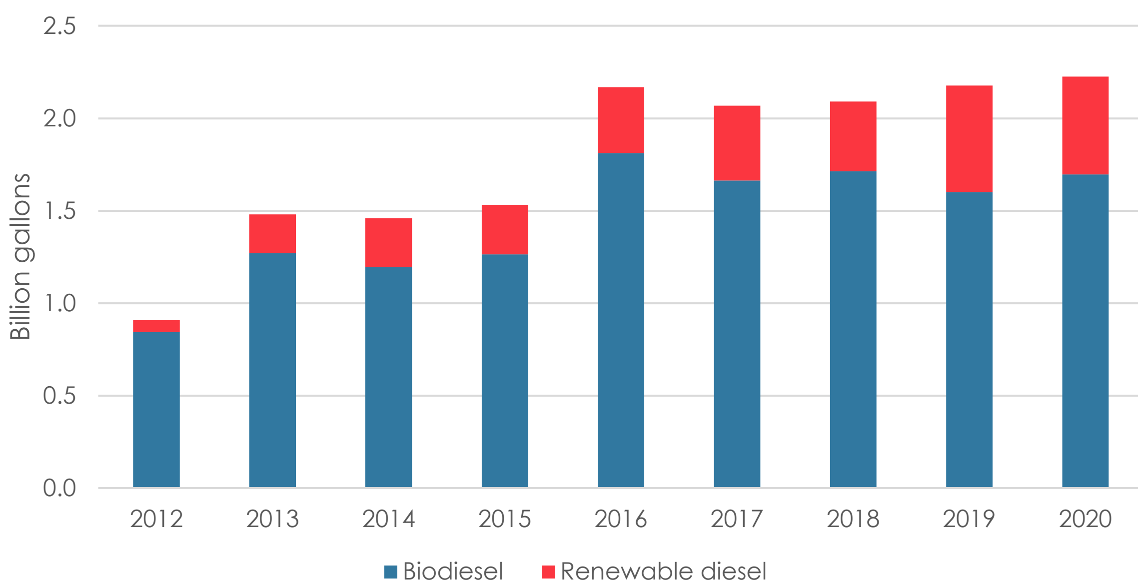

Figure 3. Supply of biodiesel and renewable diesel under the RFS (RDE)

Source: U.S. EPA (2021a)

2.2. The biomass-based diesel tax credit

The U.S. Government provides a tax credit of $1 for every gallon ($0.26 per liter) of biodiesel or renewable diesel blended with petroleum diesel and supplied to the U.S. market (AFDC, 2021a). The tax credit is available to suppliers of both domestically produced and imported fuels. The tax credit is currently in place through 2022. Unlike the RFS, which is discussed in the next section, the tax credit does not identify any specific target for volume of biomass-based diesel supplied, and therefore it may be considered a secondary driver in terms of determining supplied volumes.

The role of the tax credit as a supply driver is further complicated by the fact that it has a history of lapsing and then being retrospectively reinstated (U.S. EIA, 2020b), so that for most of the past decade biomass-based diesel suppliers could not guarantee that they would receive the credit at the time at which fuel was supplied.

2.3. California Low Carbon Fuel Standard

As well as receiving considerable support from federal incentives, renewable diesel supplied in California can generate credits under the Low Carbon Fuel Standard (LCFS). The LCFS is a state-level complement to the RFS, under which suppliers of lower carbon intensity energy to transport receive tradable credits which are used by fossil fuel suppliers to meet carbon intensity reduction targets. When renewable diesel is supplied to California it therefore becomes eligible to generate LCFS credits in addition to receiving RINs and the tax credit. Renewable diesel is particularly appealing as a compliance option under the LCFS due to the lack of a blend limit, as company obligations may be challenging or impossible to meet solely by blending conventional ethanol and biodiesel at current blend limits (cf. Malins, 2018b). Renewable diesel is the only compliance option under the LCFS for which fuel supply can be readily increased without requiring specialist vehicles or changes to blend limits, and increasing the supply of renewable diesel has proved to be one of the simplest ways for fuel suppliers to generate additional LCFS credits. In 2019 the supply of renewable diesel to the California market reached 600 million gallons (Figure 4).

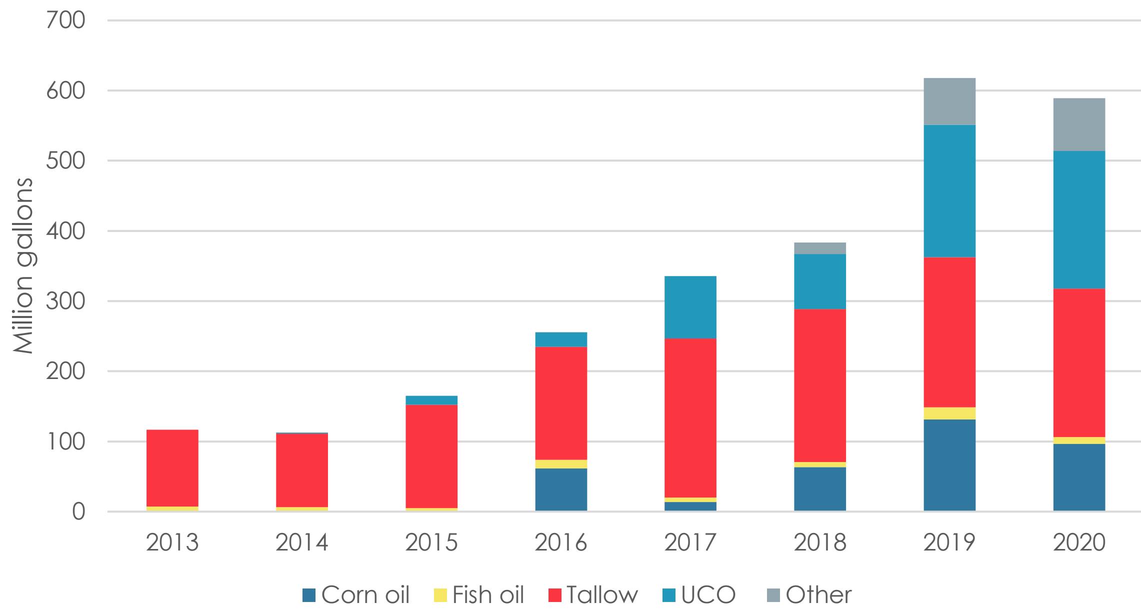

Figure 4. Renewable diesel supply by feedstock under the LCFS

Source: CARB (2021a), volumes inferred from credit generation and assumed carbon intensities.

Since the start of 2020, the average price reported for LCFS credit trades is 194 $/tCO_2e$ (CARB, 2021c). At that credit price, the LCFS could be worth between \$0.70 and \$1.70 per gallon of renewable diesel supplied, depending on feedstock and carbon intensity. The lower value, \$0.70 per gallon, is consistent with a soy oil based renewable diesel with a carbon intensity of 60 gCO_2e/MJ. The higher value, \$1.70 per gallon, is consistent with a used cooking oil based renewable diesel with a carbon intensity of 20 gCO_2e/MJ. The extra value available to waste-oil-based renewable diesel under the LCFS system means that the renewable diesel supplied to California overwhelmingly uses waste-oil feedstocks, and no use of soy oil is reported.[4]

This added value for renewable diesel suppliers makes California the most attractive market in the U.S. – for example Fuels Institute (2020) estimates that 80%-85% of renewable diesel consumption in 2017 and 2018 was by the California market, while the Department of Energy's Alternative Fuels Data Center notes that, "Nearly all domestically produced and imported renewable diesel is used in California due to economic benefits under the Low Carbon Fuel Standard" (AFDC, 2020).

The LCFS continues to increase in stringency, with a 20% carbon intensity reduction from the baseline required by 2030. A significant part of this will be delivered by electric vehicles (cf. Malins, 2018a), but there is also a considerable opportunity to further increase renewable diesel supply. For example, California Advanced Biofuel Alliance (2019) present an aggressive vision for diesel substitution in California, suggesting that fossil diesel could be eliminated by the supply of 2.8 billion gallons of renewable diesel (quadrupling the current rate of supply)

4 No soy oil renewable diesel is identified in the California statistics, but some fuel is identified with feedstock 'other'. Feedstocks are further discussed in chapter 5.

plus 700 million gallons of biodiesel. The California Air Resources Board itself is more moderate. In 'illustrative compliance scenarios' published in 2018 (CARB, 2018), CARB considers scenarios with up to 1.8 billion gallons of renewable diesel and jet fuel being supplied.

2.4. Oregon Clean Fuels Program

Oregon has a Clean Fuels Program (CFP) that is similar to the California LCFS, and therefore is another attractive market for renewable diesel supply. Since the start of 2020, the average price for CFP credits has been 127 $/tCO_2e$, which is equivalent to a value of \$0.50 per gallon of renewable diesel supplied at a carbon intensity of 65 gCO_2e/MJ and \$1.24 per gallon of renewable diesel supplied at a carbon intensity of 20 gCO_2e/MJ.

Oregon data (Oregon DEQ, 2021b) shows that renewable diesel consumption in the state reached 18 million gallons in 2020 (Figure 5). This is still only a fraction of consumption in California, but shows that the CFP is starting to make Oregon a market of interest for renewable diesel supply.

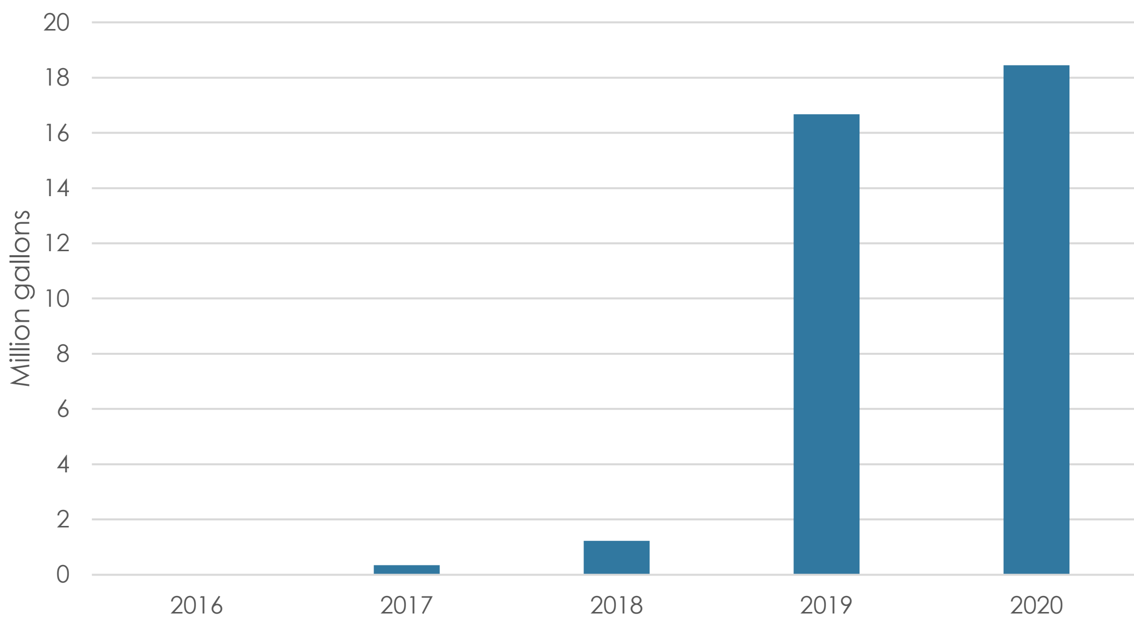

Figure 5. Renewable diesel consumption in Oregon

Source: Oregon DEQ (2021b)

The only renewable diesel producer with pathways registered under the Oregon CFP is REG-Geismar, with pathways for UCO, DCO and animal fats. There are also generic temporary pathways for waste based and virgin vegetable-oil-based fuels. Data released through UC Davis (see Figure 6) shows that the feedstock mix for renewable diesel in Oregon is dominated by tallow.

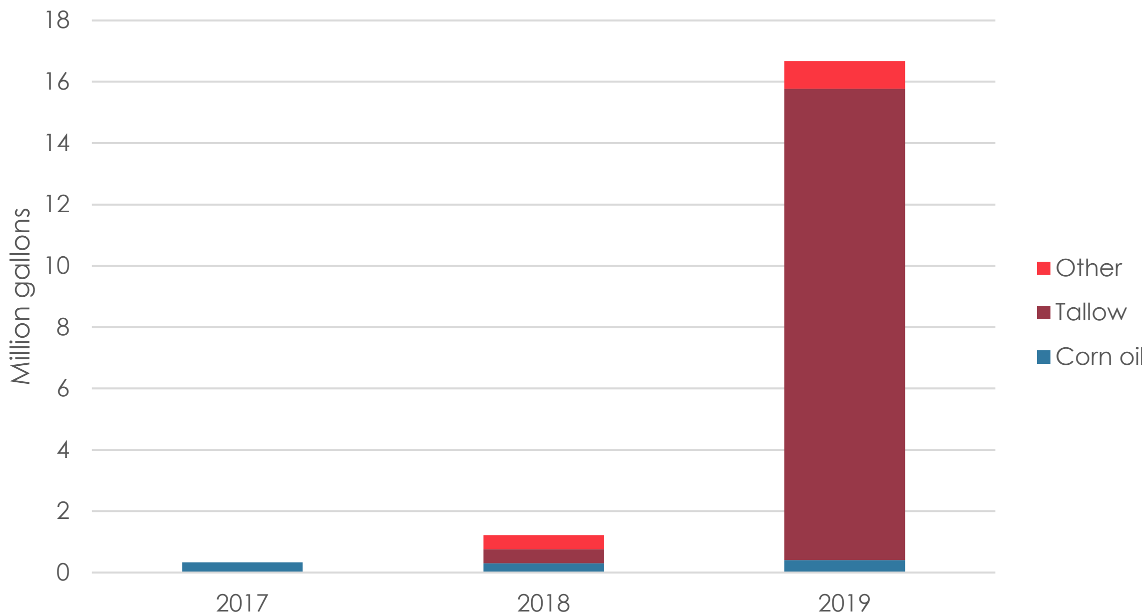

Figure 6. Feedstocks for renewable diesel supplied under the Oregon CFP

Source: Smith (2020)

2.5. Overall value of support

The combination of federal support through the RFS and tax credit with state support through LCFS-like programs represents a compelling value proposition for renewable diesel producers.

Figure 7 compares the cost of renewable diesel production as reported by Brown et al. (2020) to the value proposition for renewable diesel. The cost range reflects variation in feedstock cost and different business models (co-processing, refinery conversion, standalone facility). The value proposition is based on an indication of the 'energy value' of the fuel based on the price of a gallon of fossil diesel fuel (Lane, 2021), the value of the biomass -based diesel blender tax credit, and the potential value of the D4 RIN and of state credits (see note to table for explanation of ranges illustrated). Renewable diesel production is potentially profitable when the value proposition including regulatory incentives is greater than the production costs.

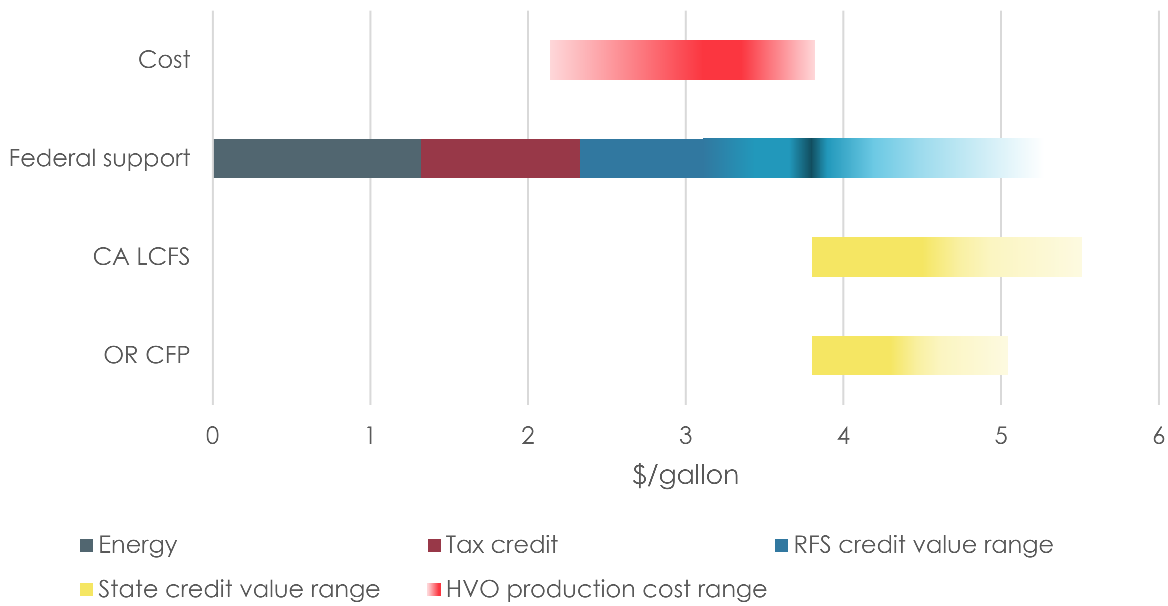

Figure 7. Indicative cost and value for renewable diesel sold into the California market

Source: Brown et al. (2020), Lane (2021), CARB (2021c), Oregon DEQ (2021a), U.S. EPA (2021d)

Production cost range as reported by Brown et al. (2020), energy value as reported by Lane (2021). RFS credit value ranges show value given minimum reported price since start of 2020 (solid part of bar) and then range to highest reported price since start of 2020 (shown as gradient, with average price since 2020 indicated by darker color). Range for state credits is based on average reported credit price since start of 2020 and ranges for renewable diesel carbon intensity from 20 to 60 gCO2e/MJ for California and from 20 to 65 gCO2e/MJ for Oregon (see sections 3.3 & 3.4). State credit value is shown as if added on top of average D4 RIN value since the start of 2020.

It is apparent from Figure 7 that the combination of the tax credit and the value of the RIN is currently likely to be enough to make renewable diesel supply profitable even without the value of state incentives. The state incentives represent a significant boost to the profit margin, however, and thus it is hardly surprising that California and Oregon account for a significant fraction of the national renewable diesel supply (see section 4.3). The Energy Information Administration (EIA) anticipates that the majority of the renewable diesel produced in the U.S. will continue to be supplied to the West Coast for the foreseeable future (U.S. EIA, 2021h). This potentially includes supply to Washington State with the introduction of its own Clean Fuel Standard, scheduled to enter into force no later than 2023 (Washington State Department of Ecology, 2021).

3. Renewable diesel production and capacity

Capacity to hydrotreat oils and fats and produce renewable diesel has increased rapidly over the past decade, supported by the policies mentioned in the previous chapter. This chapter first reviews the production, imports and supply of renewable diesel, and then reviews existing and planned hydrotreated renewable diesel capacity in the United States. It is thereby shown that planned capacity may be outpacing the rate of increase of renewable diesel demand under the RFS and state policies. The following chapter discusses the market implications of this rapid capacity growth.

3.1. Renewable diesel (and renewable jet) production

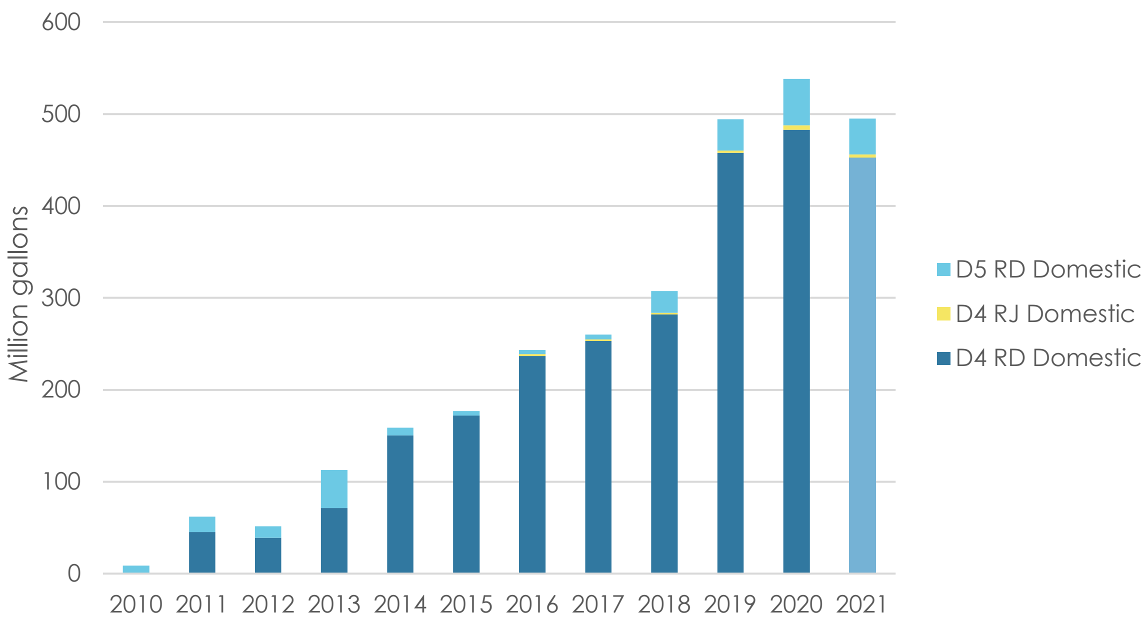

Figure 8. RIN generation by different classes of U.S. produced renewable diesel and jet fuel, 2010 to 2021*

Source: U.S. EPA (2021b)

**Data for 2021 covers January to August only.*

The EIA does not directly publish data on U.S. renewable diesel production, although it does publish estimates of capacity as detailed below in section 4.5. U.S. renewable diesel production can be inferred, however, from reporting by the EPA of the number of RINs generated. Given the considerable value to renewable diesel suppliers from RINs (cf. section 3.5), any renewable diesel producer not receiving support from the RFS would be at a very significant competitive disadvantage, and therefore we assume here that there is no significant volume being produced without generating RINs. It is possible that some volumes of fuel are being produced using feedstocks that do not yet have EPA approved renewable diesel pathways (e.g., canola renewable diesel) and therefore not receiving RINs, but if so we would expect the associated volumes to be small.

Figure 8 shows that in 2020 RINs were generated on 540 million gallons of domestically produced hydrotreated renewable fuels[5], of which 5 million gallons was jet fuel and the rest renewable diesel. Most of this fuel generated D4 RINs – this is domestically produced separately-processed renewable diesel. The fuel generating D5 RINs is co-processed renewable diesel, accounting for a relatively modest 50 million gallons in 2020.

3.2. Renewable diesel imports

In addition to domestic renewable diesel production, the U.S. market is supplied with renewable diesel imports (Figure 9). In 2020 the only country from which the U.S. was identified as importing renewable diesel is Singapore. EIA company-level import data (U.S. EIA, 2021a) shows that all of these imports are reported by Neste Oil, and we therefore assume that all of this imported renewable diesel is produced at the 1.3 million metric ton per year Neste renewable diesel facility there (Neste, 2021).

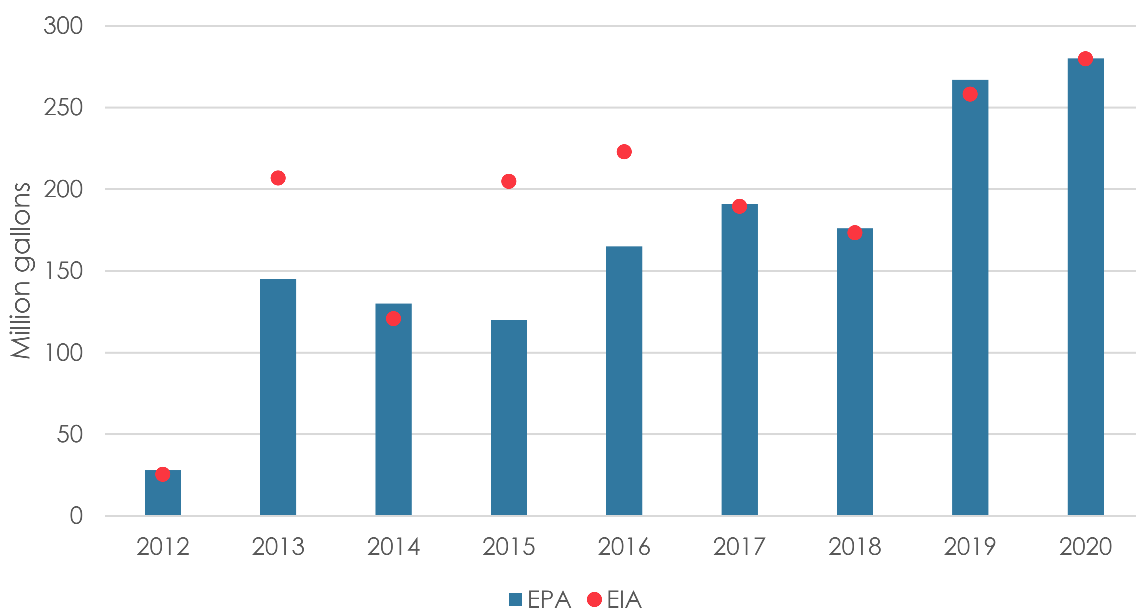

Figure 9. U.S. renewable diesel imports

Source: U.S. EIA (2019b); U.S. EPA (2021a). Note that the EIA and EPA values are not exactly aligned, especially in earlier years. It is not clear to us what the reason for this discrepancy is.

5 Note that not all fuel for which RINs are generated ends up being supplied to the U.S. transportation fuel market. RINs on biofuel supplied to non-RFS markets must be retired, and there is therefore a discrepancy between volumes of fuel on which RINs are generated as shown in Figure 8 and volumes of fuel reported by EPA as supplied to transportation.

Almost all of this material is imported by Neste through California, with the other 15 million liters coming to Oregon (U.S. EIA, 2021a, 2021f). Given that the value signal for renewable diesel is stronger under the California LCFS market than elsewhere in the country (as discussed in more detail in section 3.3), it can be assumed that this imported material is also supplied to the California market. On this basis the current renewable diesel supply to California is about half imports from Neste and half from other sources.

3.3. Renewable diesel exports

U.S. EPA (2021a) identifies a significant increase since 2017 in the volume of renewable diesel being exported from the United States (Figure 10). To the best of our knowledge EIA does not report on renewable diesel exports, and the lack of trade codes to clearly distinguish renewable diesel from other fuels/products makes it difficult to identify the destination for these exports. The only likely markets for renewable diesel exports are Europe and Canada (Bradford & Hayes, 2019), but it is unclear what volumes of renewable diesel has been exported to each.

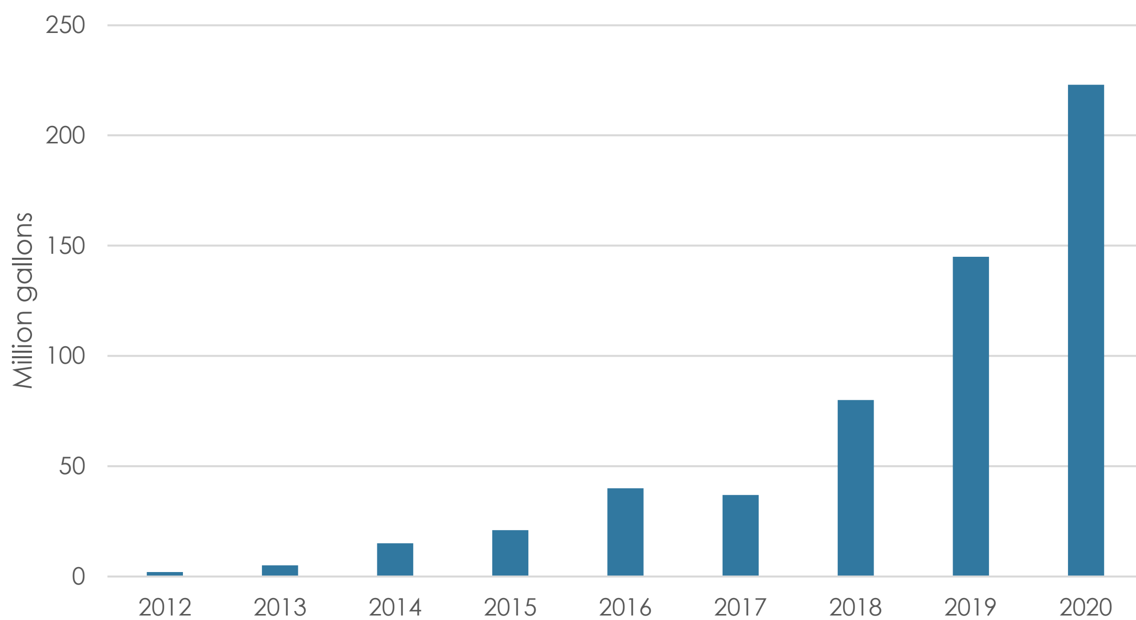

Figure 10. U.S. exports of renewable diesel

Source: U.S. EPA (2021a)

In 2019, for example, Canada is reported to have consumed about 100 million gallons of renewable diesel (ICF Canada, 2020). This is less than the 145 million gallons reported as exported from the U.S. and is likely to include some renewable diesel imported from Singapore and Europe (Bradford & Hayes, 2019). On this basis one could conclude that the U.S. must also be exporting a significant quantity of renewable diesel to Europe – however the USDA Foreign Agricultural Service do not identify the U.S. as a source of exports to Europe (Flach et al., 2021), and we have not found other independent evidence of a significant export flow to the EU. We are therefore unable to draw a firm conclusion about the destination of U.S. renewable diesel exports without access to additional data.

3.4. Renewable diesel supply by region

Data from EPA provides a basis to identify the level of renewable diesel production in the U.S., but there is no national dataset identifying where renewable is being supplied. The volumes of this fuel that are supplied in California and Oregon are reported under the LCFS and CFP respectively, and since 2018 the data suggests that these markets have accounted for 100% of U.S. renewable diesel supply, as shown in Figure 11.

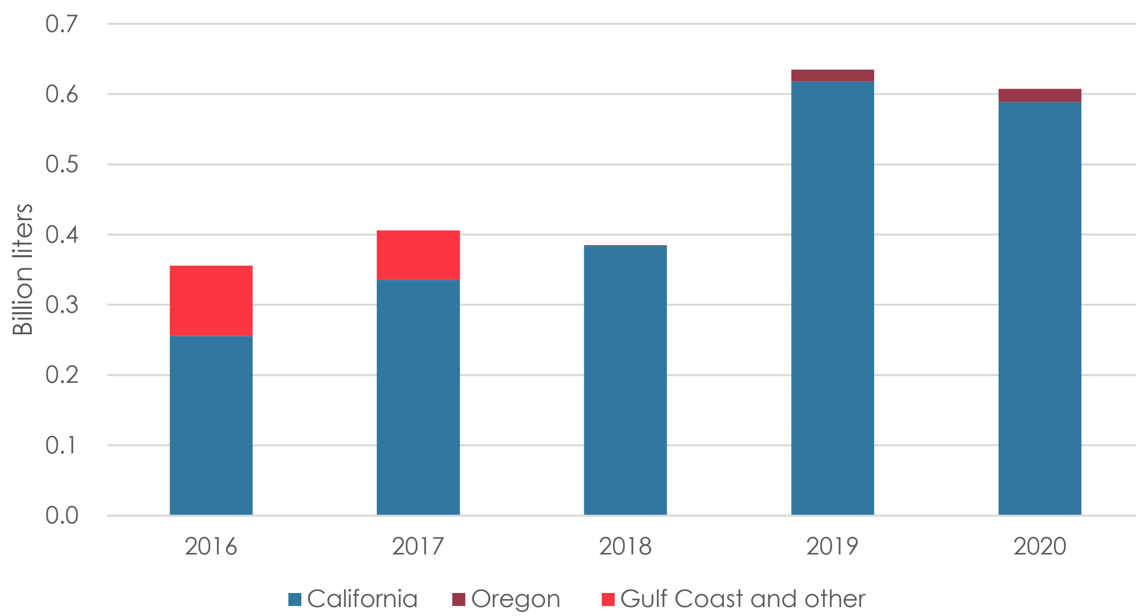

Figure 11. U.S. renewable diesel supply by region

Source: Own estimation based on consideration of CARB (2021a); Fuels Institute (2020); Oregon DEQ (2021b); U.S. EPA (2021a).

It is not trivial to reconcile the various sources of official data on renewable diesel supply, which has resulted in some confusion in the literature about total volumes supplied and whether there is still a significant volume supplied outside of California and Oregon. For example, Fuels Institute (2020) provides detailed estimates of renewable diesel supply by refining region ("PADD", standing for Petroleum Administration for Defense Districts) based on cross referencing data on renewable diesel production and imports and renewable diesel transfers between PADDs which are reported by EIA. In that analysis, the Gulf Coast region (PADD 3) is identified as still consuming a significant amount (over 200 million gallons) of renewable diesel in 2018. This is contradicted, however, by CARB and EPA reporting. Since 2018 CARB has actually been reporting a slightly larger volume of renewable diesel supplied for transportation in California than U.S. EPA (2021a) report as being supplied to the whole country, which suggests that all renewable diesel produced in PADD 3 is now either being shipped to California or Oregon or being exported. We believe that it is likely that the EIA dataset used by Fuels Institute (2020) to identify fuel movements is incomplete – however it is possible that our own analysis has missed something and understates supply of renewable diesel in regions other than from the West Coast.

3.5. Current renewable diesel capacity

The U.S. Energy Information Administration reports that as of the start of 2021 the U.S. had about 800 million gallons of renewable diesel production capacity across 6 plants (Table 2). This does not include co-processing capacity.

Table 2. Capacity of renewable diesel facilities in the U.S.

State	Name	Capacity (million gallons)
Kansas	East Kansas Agri-Energy Renewable Diesel	3
North Dakota	Dakota Prairie Refining LLC	192
Louisiana	Diamond Green Diesel LLC	337
	REG-Geismar LLC	100
Wyoming	Wyoming Renewable Diesel CO	117
California	Altair Paramount LLC	42
Total		**791**

Source: (U.S. EIA, 2021i)

The total capacity has increased during the year and by July had reached about 900 million gallons (U.S. EIA, 2021d).

3.5.1. East Kansas Agri-Energy

The smallest of the listed currently operational facilities, East Kansas Agri-Energy's facility is co-located with an ethanol distillery. East Kansas Agri-Energy state that the facility processes DCO from the ethanol plant along with "other feedstocks processed on the market" (East Kansas Agri-Energy, 2015). They report the corn oil output from the ethanol plant as about 5.5 thousand metric tons; this would cover about half their feedstock demand if operating at full capacity. The only renewable diesel pathway registered for East Kansas Agri-Energy under the LCFS is for DCO (CARB, 2021b).

3.5.2. Dakota Prairie Refining

Dakota Prairie Refining is a converted oil refinery at Dickinson, North Dakota, run by Marathon (Marathon, 2021). Production started at the end of 2020 and the facility is due to reach full capacity by the end of 2021. Dakota Prairie Refining has LCFS pathways for fuel production from soy oil and CDO (CARB, 2021b), and reporting in the business press similarly identify CDO and soy oils as feedstocks[6].

3.5.3. Diamond Green Diesel

Diamon Green Diesel's plant at Norco Louisiana is the largest operational facility in the U.S., and has approved LCFS pathways for UCO, DCO and tallow (CARB, 2021b). The plant produced its first fuel in 2013 and was scheduled for a further capacity expansion during 2021 (Diamond Green Diesel, 2021) – this is likely to be part of the national capacity expansion identified in the EIA statistics between January and July.

3.5.4. REG-Geismar

REG Geismar's plant has LCFS pathway for renewable diesel from UCO, tallow, DCO and soy oil (CARB, 2021b). REG report production of 75 million gallons of renewable hydrocarbons from the plant annually (REG, 2021), which suggests about 75% capacity utilization. For 2018, REG's annual report (REG, 2019) shows soy oil consumption of 160 thousand metric tons, canola oil consumption of 240 thousand metric tons and 'lower-cost' feedstock consumption of 1.4 million metric tons, which is 77% of total feedstock consumption. These feedstock quantities cover both renewable diesel and biodiesel production.

3.5.5. Wyoming Renewable Diesel

The Wyoming Renewable Diesel plant was developed by The Sinclair Companies but was recently sold to HollyFrontier, becoming part of the HF Sinclair Corporation[7]. The plant has only a soy oil pathway registered under LCFS (CARB, 2021b), but HollyFrontier's website states that it supplies both soy and tallow biodiesel to California[8].

3.5.6. Altair Paramount

The Altair Paramount facility, now owned by World Energy, has LCFS pathways for renewable diesel from soy oil, and for tallow from the U.S., Canada, and Australia (CARB, 2021b). It is notable for having been one of the first producers of hydrotreated aviation fuels.

6 E.g. https://www.ogj.com/refining-processing/refining/article/14208184/marathon-completes-start-up-of-north-dakota-renewable-diesel-refinery; https://www.nsenergybusiness.com/projects/dickinson-renewable-diesel-facility/

7 https://uk.finance.yahoo.com/news/hollyfrontier-corporation-holly-energy-partners-100000254.html

8 https://hollyfrontier.com/investor-relations/press-releases/Press-Release-Details/2021/HollyFrontier-Corporation-and-Holly-Energy-Partners-Announce-Combination-with-Sinclair-Oil-and-Formation-of-HF-Sinclair-Corporation/default.aspx

3.5.7. Capacity utilization

Comparing the domestic RIN generation recorded in December 2020 (cf. section 4.1) to EIA's estimate of operational capacity on 1 January 2021 gives a 68% rate of capacity utilization for these facilities in that month. RIN generation fell slightly in January 2021 suggesting capacity utilization in that month of 57%.

3.6. Co-processed renewable diesel capacity

Two facilities have pathways to supply co-processed renewable diesel to the California LCFS market. Co-processing refers to the practice of adding some fraction of oils and fats to the petroleum feed of appropriate refinery units, for example the distillate hydrotreaters that are used to reduce the sulfur content of diesel fuel for on-road use. Co-processed renewable diesel is eligible to generate D5 advanced biofuels RINs rather than D4 biomass-based diesel RINs (see section 3.1). As shown in Figure 8 below, this co-processed renewable diesel is a small fraction of the overall renewable diesel supply.

Co-processing rates of up to 30% renewable content are reported in the literature (Johnson, 2019), and it is our understanding that rates of 10-15% may be typical in co-processing facilities. Kern Oil in California reports that they include up to 5% renewable content in their finished diesel (Kern Oil & Refining Co., 2020). The other renewable diesel co-processor is BP's Cherry Point refinery, which Lane (2021) identified as having capacity to produce up to 42 million gallons a year.

The 50 million gallons of renewable diesel generating D5 RINs in 2020 (cf. section 4.1) is consistent with BP's Cherry Point refinery running at or near its reported capacity with some modest additional production by Kern Oil (see section on co-processing capacity above).

3.7. Expansions to renewable diesel capacity

Hydrotreated renewable diesel (and jet) production capacity is currently increasing rapidly, not just in the United States but around the world. Analysis by U.S. EIA (2021h) of capacity expansion announcements suggests that capacity could reach 5 billion gallons by 2024. This assessment from EIA is not a forecast, rather it is a summary of what would be delivered if all announced projects are built on schedule. In practice this is unlikely – it is normal for some projects to be cancelled or delayed due to changing circumstances, and any forecast for the amount of capacity growth that will be achieved in practice should take this into account. For example, one forecast by ADI Analytics (Singh & Turaga, 2021) suggests that capacity growth will occur more slowly, reaching 2.6 billion gallons per year in 2024, while S&P Global Platts (2021b) predict 4 billion gallons capacity in place by 2025.

There are several more projects that have already been announced but that are unlikely to become operational by 2025. Building on a list of announced projects published by the Biofuel Digest (Lane, 2021) we have identified a total of 6.4 billion gallons of capacity at some stage of project development. These capacity numbers are illustrated in Figure 12, and the identified projects are listed by status in Table 3.

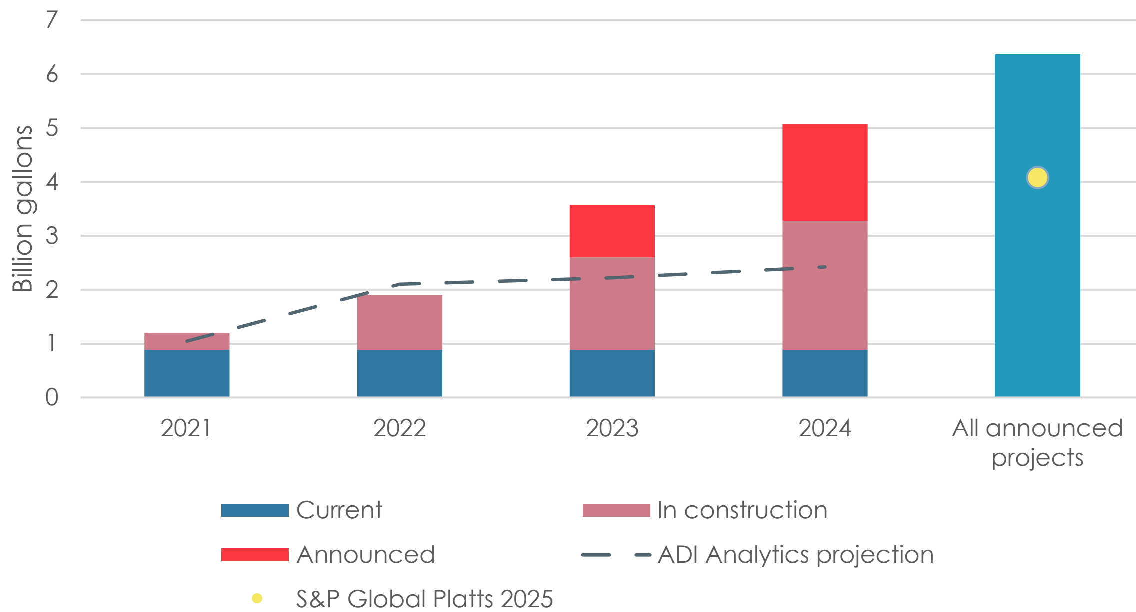

Figure 12. Potential growth in renewable diesel production capacity

Source: U.S. EIA (2021h), Lane (2021), S&P Global Platts (2021b), Singh & Turaga (2021)

It is unclear what feedstocks will be processed by the new plants coming online. The Biofuel Digest identifies the feedstock for the vast majority (6.1 billion gallons of capacity) as some combination of waste oils and virgin vegetable oils, and only 130 million gallons is identified in their database as processing waste only. Many project plans are non-committal about the potential split between use of soy oil and other oils and fats. For example, the largest four planned facilities are Marathon's refinery conversion at Martinez, Phillips 66's refinery conversion at Rodeo, Grön Fuels in Louisiana and Next Renewables. Marathon intend to process, "renewable feedstock sources including rendered fats, soybean and corn oil, and potentially other cooking and vegetable oils, but excluding palm oil" (TRC Solutions, 2021). Phillips 66 similarly state that "renewable feedstocks processed at the facility would include, but not limited to, the following: UCO; FOG; tallow (animal fat); inedible corn oil; canola oil; soybean oil; other vegetable-based oils, and/or emerging and other next-generation feedstocks (Cardno, 2021). The Grön Fuels project in Louisiana will process "soybean oil, corn oil and animal fats" (Office of Governor John Bel Edwards, 2020). The Next Renewables facility in Oregon will process, "Used cooking oils; animal tallows; seed oil; and soy oil", but no palm oil (Next Renewable Fuels, 2021). In short, the renewable diesel industry will seek to use whichever mix of feedstocks is most profitable given the balance between feedstock price and availability and the value of regulatory support.

Table 3. Targeted production capacity for renewable diesel facilities in the U.S.

Status	Facility	Target capacity (million gallons)
Operating	BP Cherry Point	40
	NextChem-Saola Energy-East Kansas Agri-Energy	10
	Holly Frontier Sinclair	120
	Total:	*160*
Expanding	Diamond Green Diesel Norco	680
	REG Geismar	340
	World Energy Paramount	300
	Total:	*1,320*
In conversion	Global Clean Energy Holdings	130
	Marathon Dickinson	180
	Total:	*310*
Under construction	CVR Wynnewood	100
	Diamond Green Diesel Texas	470
	Total:	*570*
Planning	ARA ReadiDiesel	30
	Emerald Biofuels	110
	Grön Fuels	900
	Holly Frontier Cheyenne	200
	Marathon Martinez	780
	Next Renewables	770
	Phillips 66 Rodeo	800
	Ryze Renewables Las Vegas	170
	Ryze Renewables Reno	170
	St. Joseph Renewable Fuels	90
	Total:	**4,010**
Grand Total		**6,370**

Source: U.S. EIA (2021h), Lane (2021), Barber & Godwin (2021), Bomgardner (2020)

4. Impacts of increased renewable diesel capacity on the oils and fats market

The boom in biodiesel and renewable diesel has meant that biofuel production has become a major consumer of oils and fats. OECD-FAO (2021) reports that 14% of virgin vegetable oil consumption in the U.S. is now for biofuels (70% is for human consumption and the rest is for 'other' uses such as oleochemicals). The lower value waste and residual oils and fats that can be used as feedstock could also potentially find uses in other markets such as animal feed. Increasing renewable diesel production therefore has implications for other oil and fat markets. In this chapter, we consider the implications for feedstock markets if the levels of renewable diesel capacity expansion identified in section 4.7 were to be achieved as additional supply. Chapter 6 then discusses that in practice the expansion of renewable diesel might instead result in a displacement of feedstock away from the biodiesel sector.

We are not aware of any comprehensive federal level reporting on the feedstocks used for renewable diesel in the U.S., but as we believe that all or almost all renewable diesel in the U.S. is supplied to the California and Oregon market the feedstock mix can be inferred by cross referencing LCFS credit generation data from CARB and Oregon DEQ with carbon intensity pathways under the LCFS and CFP[9] and renewable diesel supply data from EPA (CARB, 2021a; Oregon DEQ, 2021b; U.S. EPA, 2021a). The national renewable diesel feedstock mix estimated on this basis is shown in Figure 13. As the EPA do not publish renewable-diesel-specific feedstock information, the additional fuel volumes supplied away from the West Coast are identified as 'other'. Waste and residual oils are the dominant feedstocks for the renewable diesel supplied to California, accounting for at least 500 million gallons of supply in 2020. There is also some material supplied to the California market listed as "other" – we understand that this 'other' category includes fuel supplied using temporary carbon intensity pathways and could also include some soy renewable diesel.

9 Carbon intensity assumptions are required to estimate volumes from credit generation.

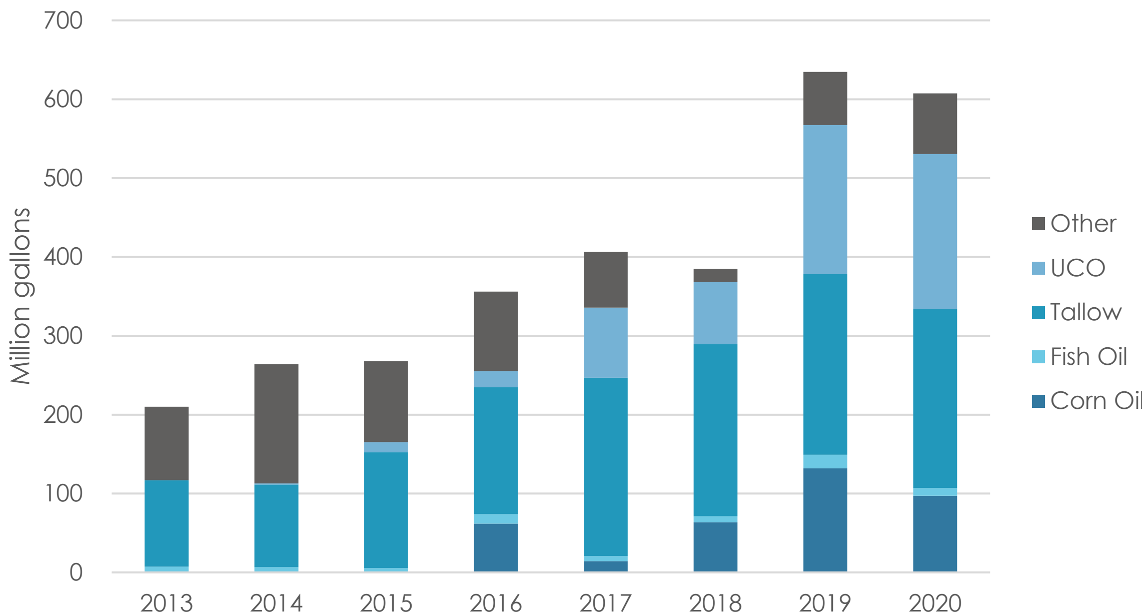

Figure 13. Estimated feedstock breakdown for renewable diesel supplied in the U.S.

Source: Own estimation based on cross-referencing data from EPA, Oregon DEQ and CARB.

While Figure 13 shows an estimated feedstock breakdown for all renewable diesel supplied in the U.S., a recent change in the way that the EIA reports on biofuel feedstock use provides a basis to estimate the feedstock mix for renewable diesel produced in the U.S. The EIA has for some years published data identifying feedstocks for biodiesel production excluding renewable diesel, but since the start of 2021 this has been replaced by a new data product detailing the U.S. feedstock mix across all biofuels (U.S. EIA, 2021b), which groups biodiesel and renewable diesel together. For 2021 up to July the overall mix of oils and fats used as biomass-based-diesel feedstocks is shown in Figure 14.

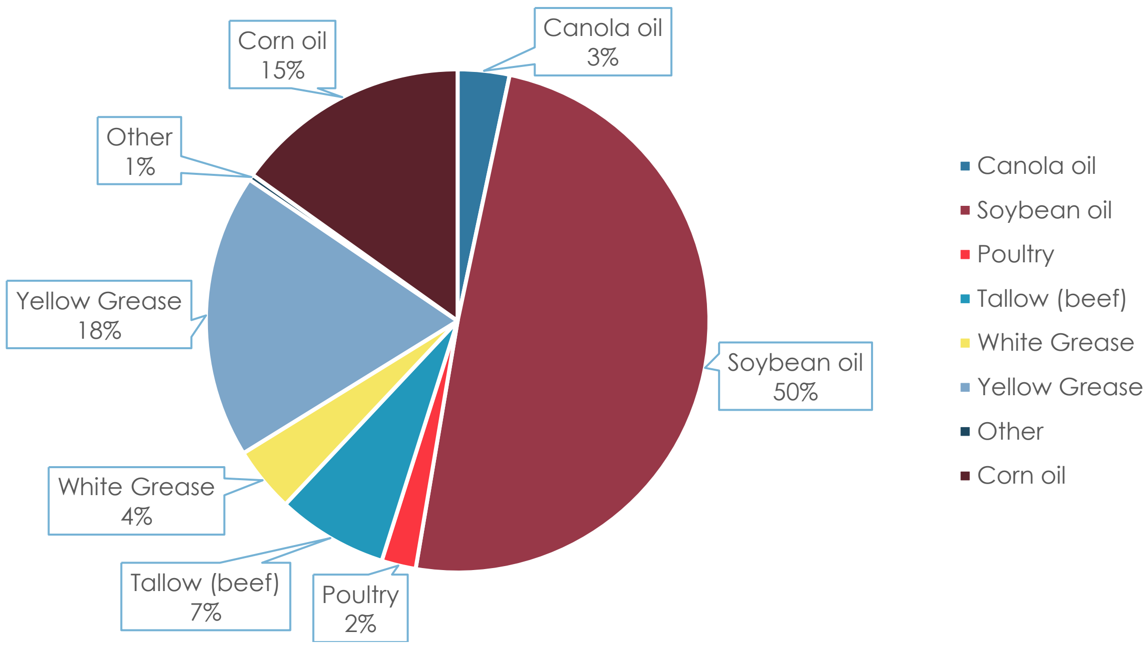

Figure 14. Feedstock mix for oil- and fat-based biofuels in the U.S., January to July 2021

Source: U.S. EIA (2021b)

While the new EIA data does not explicitly distinguish renewable diesel feedstocks from biodiesel feedstocks, the change in the scope of the EIA data at the end of 2020 from biodiesel only to biodiesel plus renewable diesel makes it possible to draw inferences about the national feedstock mix for renewable diesel production. This can be done by looking at the difference between the biodiesel plus renewable diesel feedstock mix at the start of 2021 and the biodiesel-only feedstock mix at the end of 2020. Assuming that the feedstock composition for renewable diesel is somewhat stable, the change in reported feedstock use between the old and new data can be taken as indicative of the feedstock used for renewable diesel. Figure 15 shows the feedstock mix obtained by taking the difference between the reported feedstocks for biodiesel only in the second half of 2020 and the reported feedstocks for all biomass-based diesel in the first half of 2021. As we would expect, this analysis confirms that U.S. renewable diesel production is dominated by the feedstocks reported for renewable diesel supplied in California (UCO, animal fats, DCO). Comparing Figure 13 to Figure 15 we see that there appears to be a larger fraction of animal fats used for the renewable diesel supplied in the U.S. than for domestic production. This suggests that animal-fat-based fuels make up a large fraction of imports, but given that the data for both of these figures are derived based on making assumptions on related datasets we are cautious of drawing firm conclusions from the differences between them. Taken together, the California and EIA data suggest that there is at most a relatively limited use of soy oil as a feedstock for renewable diesel supplied in the U.S.

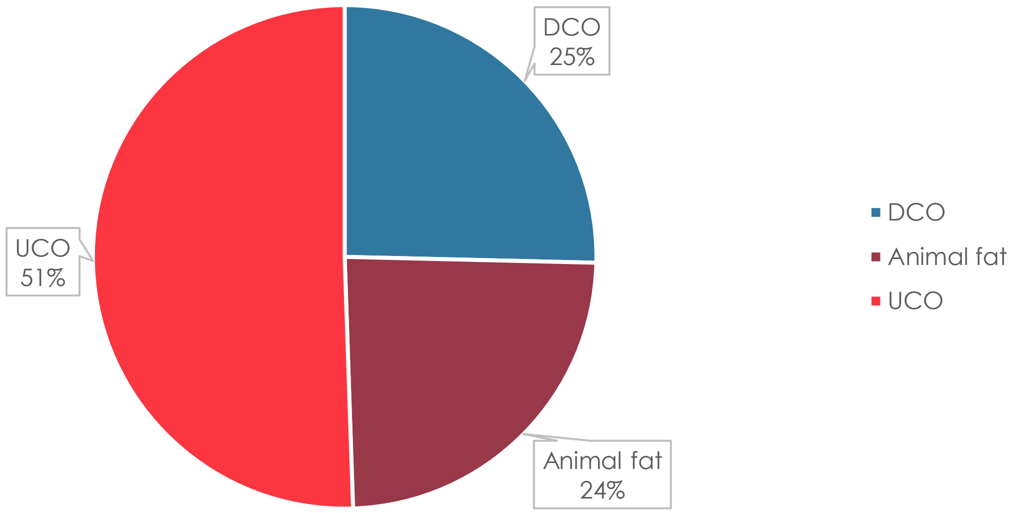

Figure 15. Renewable diesel feedstock mix implied by difference between EIA datasets

Source: Own calculation based on U.S. EIA (2021b) and U.S. EIA (2019a), see main text.

While virgin vegetable oils are not currently used (to any large extent) for renewable diesel production, they remain important for the biodiesel market as shown in Figure 14. As noted in section 4.7 most planned renewable diesel facilities in the U.S. identify virgin vegetable oils as potential feedstocks. Looking at all biomass-based diesel production in the U.S. (including biodiesel), soy oil and canola oil remain important. Extrapolating data up to September from U.S. EIA (2021b) for feedstocks used for all biomass-based diesel suggests that in 2021 the industry will consume around 3.9 million metric tons of soy oil and 600 million metric tons of canola oil, plus 1.1 million metric tons of DCO and 2.5 million metric tons of other waste and residual oils and fats. These numbers are similar to estimates of soy use for fuel for the 2020-21 marketing year from (USDA ERS, 2021) and from the World Agricultural Supply and Demand Estimates (USDA, 2021b).

4.1. Feedstock availability

The rate of planned renewable diesel capacity expansions has caused some analysts to predict a squeeze on vegetable oil supplies. If all of the announced capacity identified by U.S. EIA (2021h) were to come online as announced and operate at 100% of capacity, total feedstock consumption for renewable diesel would increase by 17 million metric tons, a factor of 10 by 2024 (Figure 16). In April, Reuters reported[10] that BMO Capital Markets had predicted an incremental demand increase for soy oil of 3.6 million metric tons by 2023. This would be

10 https://www.reuters.com/business/energy/us-renewable-fuels-market-could-face-feedstock-deficit-2021-04-09/

consistent with about a third of the additional capacity identified for 2023 by the EIA producing soy-oil-based fuel.

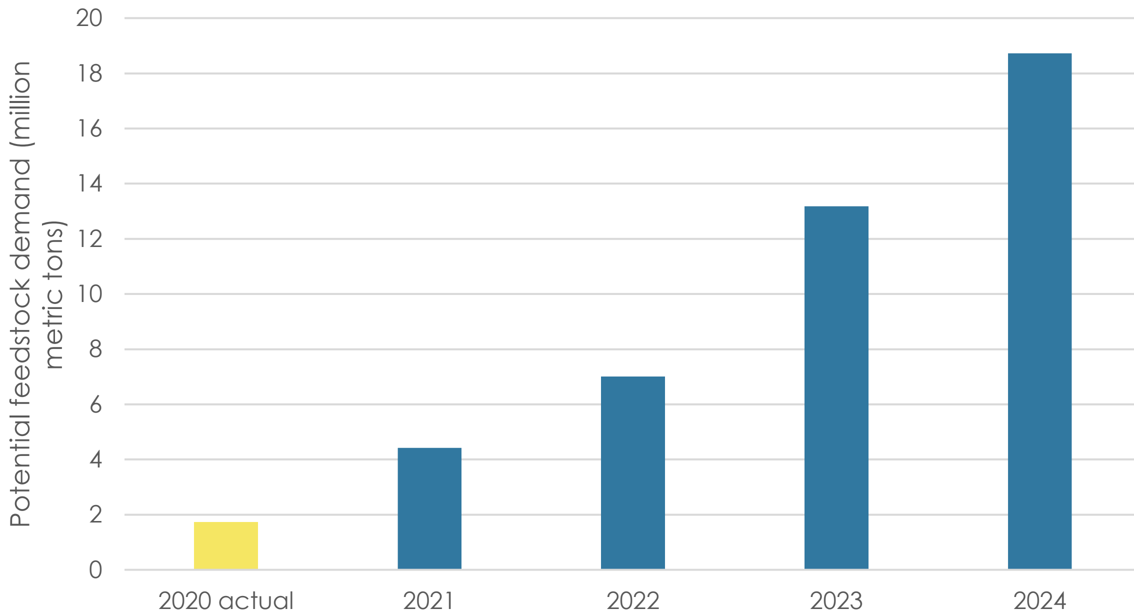

Figure 16. Potential feedstock demand for renewable diesel if all announced projects produced at 100% of capacity

Source: calculated based on U.S. EIA (2021h)

This is not an insignificant increase in demand. The United States currently produces slightly less than this amount as virgin vegetable oil[11], about 14 million metric tons of vegetable oils a year in total. It consumes roughly the same amount of vegetable oil in food applications (OECD-FAO, 2021). This shows that consumption of food-grade oils for biofuel production is supported by U.S. net vegetable oil imports. Indeed, historically increases in biomass-based diesel production in the U.S. have coincided with increases in vegetable oil imports (Figure 17), including in particular imports of palm oil and canola/rapeseed oil (cf. Searle, 2014).

11 Not including waste vegetable oils and animal fats.

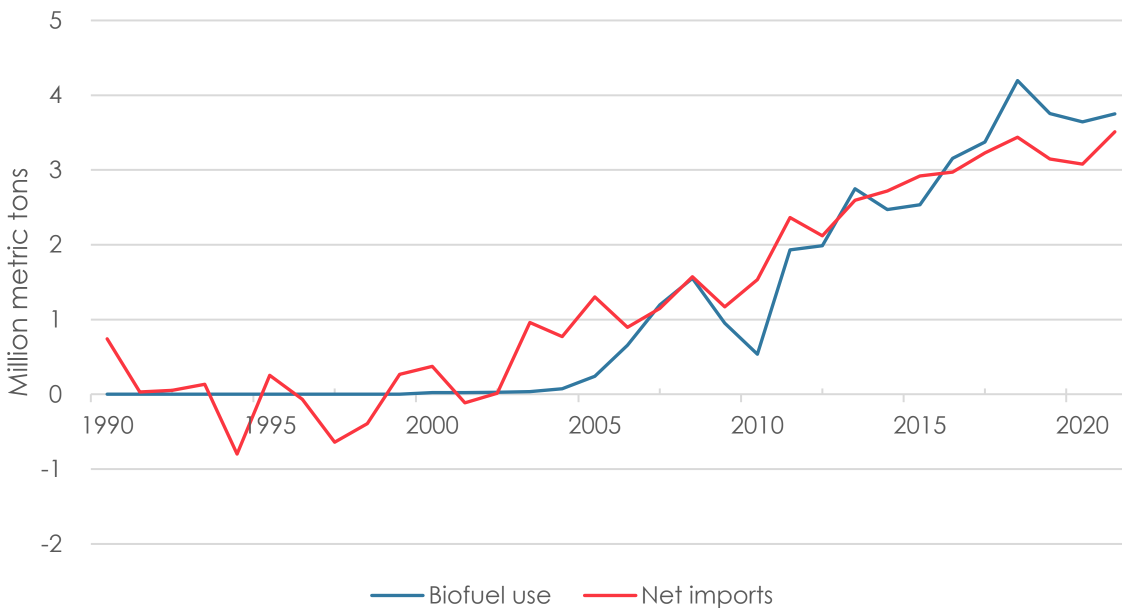

Figure 17. Increases in U.S. consumption of vegetable oils for biofuel production and in net vegetable oil imports, 1990 to 2021

Source: OECD-FAO (2021)

It is not realistic to expect all announced facilities to be completed on time and to achieve full utilization, but let us consider what would be needed to deliver even half of this maximum rate of expansion in the 2025 timeframe. To achieve 2.5 billion gallons of additional renewable diesel production without displacing other uses would require an increase in feedstock supply by 7.6 million metric tons.

OECD-FAO (2021) projects a 200 thousand metric ton increase in U.S. vegetable oil production from 2020 to 2025. The projection for soy oil production only from the World Agricultural Supply and Demand Estimates (WASDE) (USDA, 2021a) is more aggressive, anticipating a 1.2 million metric ton increase between the 2020/21 and 2025/26 seasons alongside a 1.4 million metric ton increase of the use of soy oil for biofuels, but this is still well short of the scale required.

There may also be some potential to increase collections of waste/residual oils and fats, but this is likely to be limited. In setting the 2021 biomass-based diesel obligation, the EPA noted that, "Most of the waste oils, fats, and greases that can be recovered economically are already being recovered and used in biodiesel and renewable diesel production or for other purposes." U.S. EPA (2021a) suggests that production of biofuels from waste and residual oils and fats may be expected to increase at about 30 million gallons a year, based on extrapolating the trend seen from 2012 to 2020. That implies an increase in supply of about 550 thousand metric tons by 2025. Zhou et al. (2020) reviews the potential for increased supply of waste oils and fats, but also for increases in demand from other markets. There is some prospect of increased generation of animal fats associated with increased livestock numbers, but Zhou et al. (2020) finds that demand for animal fats from other markets is expected to increase faster than production so that there will be no increase in availability for biofuels. (Zhou et al., 2020) finds a better outlook for UCO availability, with an increase of about 120 thousand metric tons from 2020 to 2025.

It is noted in U.S. EPA (2021a) that production of biofuels from DCO could in theory be increased by 200 million gallons per year, but that this would "require shifting distillers corn oil from other existing uses" which would then need to be met with alternative materials, and would therefore only shift rather than resolve the overall feedstock supply issue. DCO production is expected by Zhou et al. (2020) to decrease after 2020 in line with an anticipated reduction in corn ethanol supply volumes, but more recent USDA projections have ethanol consumption stable from 2020 to 2030 (Interagency Agricultural Projections Committee, 2021). U.S. EPA (2019) anticipated that increased deployment of corn oil extraction from distillers' grains would allow for modest production increases (suggesting 50 a thousand metric ton increase from 2019 to 2020), but EIA data suggest that biofuel production from DCO in fact fell slightly in 2020 (U.S. EIA, 2020a). In any case, removal of additional corn oil from distillers' grains would increase feedstock availability for renewable diesel production, but proportionately reduce the mass and calories available in distillers' grains used for animal feed. Based on the analysis in Zhou et al. (2020) it seems reasonable to conclude that the EPA's 550 thousand metric tons can be taken as a maximum on the additional supply of these resources that could be available for biofuels by 2025.

Adding the USDA forecast for increased soy oil production to the EPA forecast for increased use of waste oils and fats gives a total supply increment from 2020 to 2025 of 1.75 million metric tons – only a quarter of what would be needed to deliver 2.5 billion gallons of production per year. This implies that if renewable diesel production expands in line with current plans, then either the feedstock must be displaced from other current users or U.S. vegetable oil imports will need to increase dramatically to compensate.

4.2. Imports of waste oils and fats

The U.S. is currently understood to be a net exporter of UCO. Fuels Institute (2020) identifies UCO with HS code 15 18 00[12], and UN Comtrade (2020) data shows exports of up to 350 thousand metric tons a year[13], and more limited imports (Figure 18). The destination of these exports is dominantly Singapore (likely for processing at the Neste facility) and Europe (likely for conversion to biodiesel and supply under the EU Renewable Energy Directive and UK Renewable Transport Fuel Obligation). It is likely that this HS code also includes some material that is sold into non-biofuel markets. USA Trade data also shows significant exports to Singapore of pig fat and tallow (300 thousand metric tons and 50 thousand metric tons respectively in 2020) at prices that could be consistent with biofuel feedstock use.

12 Animal or vegetable fats and oils and their fractions; oxidized, boiled or otherwise chemically modified, (excluding those of heading no. 1516), inedible mixtures or preparations of fats or oils.

13 This is more than reported by (Fuels Institute, 2020); we believe that they referenced USA Trade data which excluded on-road exports.

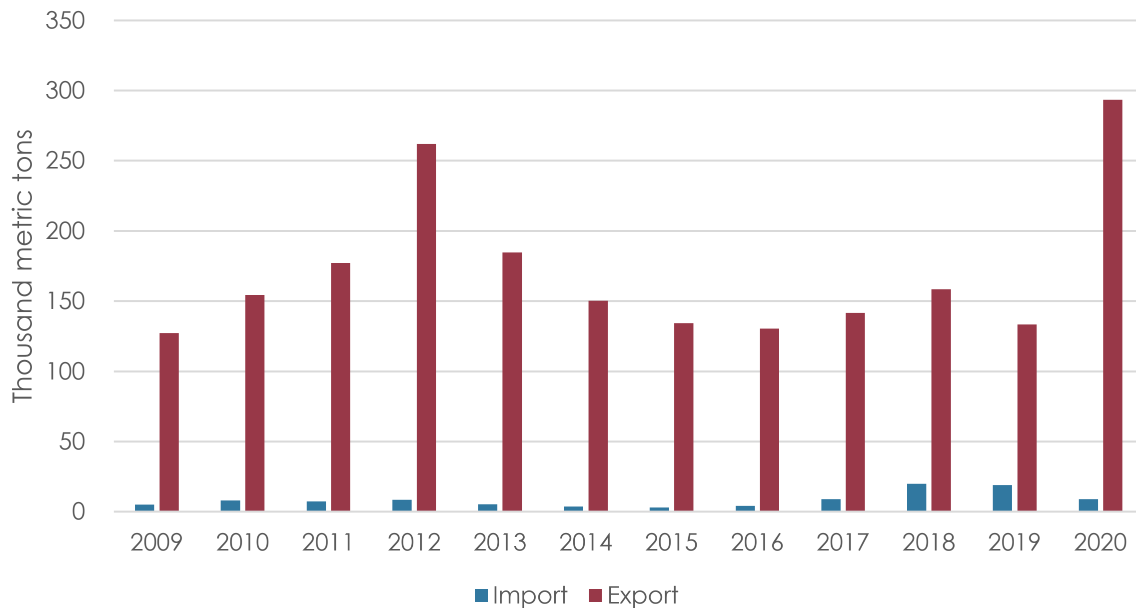

Figure 18. U.S. imports and exports of inedible oils and fats under HS code 15 18 00

Source: UN Comtrade (2020)

Feedstock availability for U.S. renewable diesel production could be increased by reducing U.S. exports of UCO and animal fats. To the extent that these materials are currently exported for processing by Neste in Singapore, this may result in reduced availability of wastes-based renewable diesel for import. Feedstock availability could also be increased by importing UCO or animal fats. The EU biofuel market already consumes large quantities of imported UCO (Flach et al., 2021), and the U.S. could follow this example and increase the sourcing of UCO or other waste oils from overseas.

It is difficult to assess the potential global supply of UCO, as its availability for biofuel use is dependent on building collection networks and supply chains. The growth of the biodiesel industry globally has encouraged the development of UCO collection industries in many countries, but there is undoubtedly still significant potential to increase collection rates. It should be noted that where collection systems already exist, this is generally because markets for UCO already exist as well. This may be local biodiesel production or animal feed use, and in some countries used cooking oil may be 'recycled' as so-called 'gutter oil' and sold to domestic consumers. This last practice is considered undesirable for health reasons and countries such as China are seeking to eliminate it, which could increase potential resource availability for biofuels. It is believed that at the global level there is still substantial scope to increase biofuel production from UCO, and Kristiana et al. (2022) estimates that it may be possible to increase the supply from Asia to other markets by millions of metric tons per year, although this level may not be readily achievable in practice – van Grinsven et al. (2020) suggests global potential closer to 3 million metric tons.

Increasing reliance on UCO imports does, however, create the risk of 'mislabeling fraud' whereby virgin vegetable oils would be incorrectly labelled as used. The added value of UCO-based renewable diesel in the LCFS and CFP markets creates an incentive to misrepresent renewable diesel from palm or soy oil as being UCO based, to increase the number of credits generated (in section 3.3 we suggest that the value difference between UCO renewable diesel and soy renewable diesel in the California LCFS could be as much as a dollar a gallon). Fraud risk in the global UCO supply chain is already an issue of concern in the EU (van Grinsven et al., 2020) and should be taken seriously if the U.S. increases its use of imports.

4.3. Increasing vegetable oil production

In the absence of waste or residual oils able to fill the gap in demand, increased renewable diesel production could only be delivered through increased consumption of virgin vegetable oils. For increased consumption to be possible without significant reductions in consumption for food (this possibility is further discussed in the next section, 5.4) the annual production of vegetable oils would have to increase by millions of metric tons.

In principle there is potential to increase U.S. vegetable oil production beyond the rate predicted in the WASDE by increasing the amount of land devoted to soy and canola. Even though soy oil remains the primary feedstock for biomass-based diesel production in the U.S., it is generally understood that soy oil demand (and price) is only a weak driver of soybean production levels. This is because most of the value of the soy crop resides in the meal co-product (Malins, 2020; U.S. EPA, 2019). Even with a strong demand for additional vegetable oil for renewable diesel processing it is therefore unclear whether soy production could be expected to expand significantly. The canola crop is likely to be more responsive to the oil market (as most of the value of the canola crop is in the oil), but total current canola oil production in the U.S. is only about 700 thousand metric tons (UN Food and Agriculture Organisation, 2020) and so it would seem unlikely that production increases on the level that would be required could be delivered. McCollum et al. (2021) review the extent to which U.S. farmers would be willing to expand oilseed production to meet additional demand from the renewable fuel industry, in particular by replacing a wheat crop or fallow period with a canola crop. They conclude, "that a highly favorable scenario may be needed for oilseed SAF production to be feasible in any of the study region states", i.e., that a large increase in the price of canola would be required to drive increases in production.

Soy oil production in the U.S. could also be increased without increasing total soybean production by increasing the amount of soybeans that are crushed within the U.S. rather than exported to be crushed overseas. The WASDE shows that about half of U.S. soybean production (60 million metric tons) is currently crushed domestically, and the other half exported. In 2020 about half of those exports went to China (UN Comtrade, 2020). Increasing the fraction of U.S. soybean production crushed domestically would allow increased meal exports while increasing domestic soy oil availability. It would simultaneously reduce the availability of soy oil from crushing in other countries, and this deficit would need to be covered with other vegetable oils. In China, for example, the main imported oil is palm oil (USDA FAS, 2021). Reducing soybean exports to China in favor of soy meal exports would be expected to lead to increased palm oil imports to China. While it would certainly be possible to deliver some increase in domestic soybean crush, it should not be taken for granted that markets could readily be found for a large increase in soy meal exports. The global import market for soybeans is many times larger than that for soy meal – for instance UN Comtrade (2020) reports that in 2020 China imported 100 million metric tons of soybeans but only two tonnes of soy meal.

If domestic vegetable oil production is not able to increase to supply the required feedstock for renewable diesel facilities, then the other alternative would be further increases in vegetable oil imports, accompanied by production increases in other countries. Figure 19 shows that since 2003 increased U.S. vegetable oil imports have been delivered by a combination of canola oil (mostly from Canada) and palm oil (mostly from Indonesia and Malaysia).

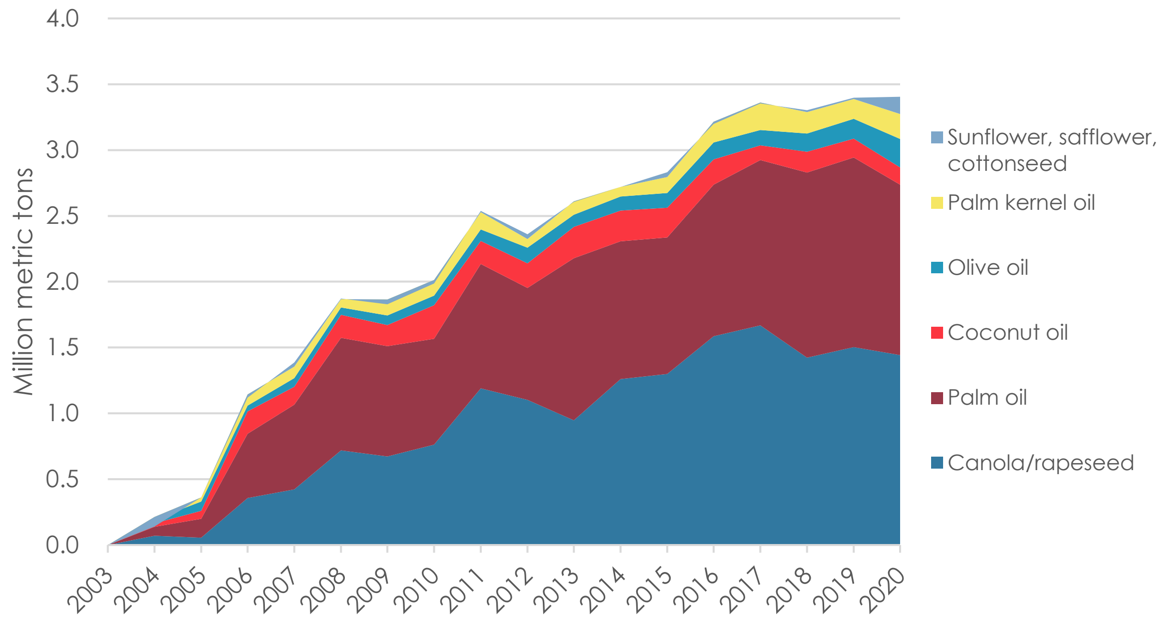

Figure 19. Increase in imports to the U.S. of major vegetable oils since 2003

Source: UN Comtrade (2020)

Increasing the global production of palm oil and/or canola oil might have other negative implications. The palm oil market is considered particularly problematic from a climate change perspective because of the link between palm oil expansion and both deforestation and peat drainage in Southeast Asia (Malins, 2018c). Indirect land use change (ILUC) estimates for the EPA and CARB suggest that increasing palm oil supply results in higher land use change emissions than for any other vegetable oil considered. As a result of these higher ILUC values renewable diesel produced from palm oil cannot generate D4 RINs or LCFS credits, but palm oil demand could still be indirectly increased.

The ILUC analyses by EPA and CARB for soy biodiesel assume that palm oil production increases will play only a limited role in meeting demand for soy oil as a biofuel feedstock. A very rapid expansion of renewable diesel production from soy oil might, however, lead to a much-increased role for palm oil palm oil as a substitute. In that case existing ILUC estimates for soy may systematically understate the link to the palm oil market (see also Santeramo & Searle, 2018).

Overall, it seems reasonable to conclude that delivering as much as 7.6 million tons of additional feedstock for renewable diesel could be expected to result in what the EPA refer to as, “market disruption, higher costs, and/or reduced GHG benefits” (U.S. EPA, 2019).

4.4. Impacts on vegetable oil prices

Indirect land use change impacts are not the only potential negative externality from renewable diesel expansion. A rapid increase in vegetable oil demand would also put upward pressure on vegetable oil prices, with negative consequences for other consumers. The question of the relationship between biofuel demand and food-commodity prices remains contentious. Some analysts continue to argue that the impact of biofuel demand on prices is weak or non-existent, but the more general consensus is that higher demand from the biofuel market does lead to higher prices overall, and that price effects can be most serious if demand increases very rapidly (Malins, 2017a).

Several market analysts have identified the current boom in renewable diesel capacity as a driver of recent price increases in the vegetable oil market (e.g. Maltais, 2021; Stratas Advisors, 2020; Terazono & Jacobs, 2021; U.S. EIA, 2021g). As can be seen from Figure 20, soy oil prices have risen to record highs since the start of 2020. Food producer's organizations such as the American Bakers' Association have called on the EPA to reduce the level of mandates under the RFS in order to reduce pressure on vegetable oil prices (Eller, 2021). With capacity increases scheduled to continue coming online until at least 2025, this upwards price pressure is likely to continue for the foreseeable future.

Figure 20. Soy oil price

Source: Hofstrand (2014)

5. Market implications of capacity expansion

As detailed in the previous chapters, over the next five years or so renewable diesel (and jet) production capacity in the U.S. is set to increase from 800 million gallons a year perhaps to as much as 6.4 billion gallons a year, an eight-fold increase. This rate of capacity increase (of the order of a billion gallons a year) is much faster than the rate of growth in the non-cellulosic advanced biofuel mandate under the RFS. As discussed in section 3.1, since the passage of the RFS2 the level of the non-cellulosic part of the advanced biofuel mandate has been a good predictor of the rate of biodiesel plus renewable diesel supply. Unless there is a significant shift in market dynamics, the size of the advanced mandate could therefore be considered a ceiling on potential renewable diesel supply. The non-cellulosic part of the advanced mandate will increase by 250 million gallons 2021 to 2022, and the annual increase averages 120 million gallons a year for the five years from 2017 to 2022. If renewable diesel meets the whole of that increase in the mandate with no change in biodiesel supply it would result in about 1.3 billion gallons in 2022.

There is nothing in the EPA's recent volume rules to suggest that it would consider it appropriate to propose dramatically higher advanced biofuel mandates after 2022. Indeed, the most recent volume rules have highlighted the risk of negative market and environmental impacts if the supply of biomass-based diesel is further increased (U.S. EPA, 2019, 2021a). In the absence of congressional action there is going to be an apparent inconsistency between the rate of renewable diesel capacity growth and the level of demand created by the RFS. This inconsistency would need to be resolved by some combination of the following outcomes:

1. Supply more U.S. produced renewable diesel to meet the RFS advanced and biomass-based diesel mandates at the expense of reduced biodiesel production;
2. Supply more U.S. produced renewable diesel to meet the RFS renewable fuel mandate at the expense of reduced corn ethanol production;
3. Supply more U.S. produced renewable diesel to meet the RFS biomass-based diesel mandate at the expense of reduced imports of renewable diesel;
4. Dispose of increased renewable diesel production by increasing renewable diesel exports;
5. Rationalization of capacity through capacity cancellations, delays or closures.

In the following sections, we discuss the implications and likelihood of each of these outcomes.

5.1. Supply more U.S. produced renewable diesel to meet the RFS advanced and biomass-based diesel mandates at the expense of reduced biodiesel production

As was illustrated in Figure 3 in section 3.1, even though the supply of renewable diesel has increased significantly in recent years the volume of renewable diesel supplied in the U.S. is still only about half the volume of biodiesel supplied. The volume of biodiesel supplied to the U.S. market peaked in 2016 and has been relatively stable since. One way to accommodate more renewable diesel within the RFS would be to deliver a corresponding reduction in the biodiesel supply, either by reducing capacity utilization or by closing some biodiesel plants. Donnell Rehagen of the National biodiesel Board has previously commented that. “There’s a limited pool of feedstock used in production of biodiesel and renewable diesel, and they all rely on that same pool, which is only so big” (Kotrba, 2018).

Renewable diesel has several advantages over biodiesel as a blendstock. It is not subject to blend limitations; it performs consistently better then fossil diesel in terms of air pollution (whereas biodiesel can reduce particulate matter but increase NOx emissions, O’Malley & Searle, 2021); and it has slightly higher energy density. The production costs for the two fuels are both dominated by feedstock (about 75% of the cost for both) but are comparable overall (Brown et al., 2020; Hofstrand, 2014). Capital expenditure requirements are greater for renewable diesel, but still account for less than 10% of levelised cost (Brown et al., 2020). Recent years have seen a number of biodiesel plant closures in the U.S. (S&P Global Platts, 2021b), and EIA data already shows a slight reduction in total U.S. production capacity from a peak of just under 2.6 billion gallons per year in 2019 to 2.4 billion gallons per year in 2021 (U.S. EIA, 2020a, 2021c). Increased competition from renewable diesel production is identified as one reason for these closures (S&P Global Platts, 2021b).

Biodiesel producers whose supply chain is based on waste and residual oils and fats may be particularly vulnerable to competition from renewable diesel producers. This is because those feedstocks will be in high demand for production of renewable diesel to be sold into the California market, where the biodiesel blend wall and NOx limits constrain the potential to increase biodiesel sales. Without access to the value of LCFS or CFP credits, biodiesel producers may not be able to compete with renewable diesel producers to secure waste oil and fat supplies. More than two million metric tons of feedstock could be made available to the renewable diesel industry by reducing production of biodiesel from waste and residual oils, allowing an additional 500 million gallons of renewable diesel production.

While some further shrinkage in the biodiesel sector seems very plausible, fully replacing biodiesel in the U.S. market may be less likely. Outside of the LCFS, CFP and similar regulations, supplying biodiesel from soybean up to a B5 blend should remain a competitive way of generating D4 RINs for compliance with the biomass-based diesel and advanced mandates of the RFS. Several states (e.g., Minnesota, Iowa, New Mexico, Kentucky, North Dakota) have biodiesel blending mandates and/or tax credits that will support continued local use of biodiesel at B5 or B20 blends (AFDC, 2021b).

If national biodiesel consumption was halved over the next five years, this would create space for an additional 900 million gallons of renewable diesel supply contributing to the RFS advanced and biomass-based diesel mandates. This is a significant volume increase, but still much less than the announced capacity increases, and therefore biodiesel displacement alone would not resolve the over-capacity issue.

5.2. Supply more U.S. produced renewable diesel to meet the RFS renewable fuel mandate at the expense of reduced corn ethanol production

Up until now, renewable diesel supply has been primarily supported by the market for D4 and D5 RINs to comply with the RFS advanced and biomass-based diesel mandates, but it is also eligible to contribute to compliance with the much larger renewable fuel mandate. The renewable fuel mandate is currently met primarily with corn ethanol, blended up to 10% by volume in gasoline as 'E10'. The EPA notes in the preamble on the proposed 2022 RFS volume rule that, "the use of E10 alone has not been sufficient to achieve the 15 billion gallons of ethanol use due to declining gasoline demand" and states that the stack of subsidies available to renewable diesel (in particular the blender tax credit, which is not available to ethanol producers) has been enough for it to contribute towards the renewable fuel mandate in recent years (U.S. EPA, 2021c).

If the advanced fuel mandate is more difficult for obligated suppliers to comply with than the renewable fuel mandate (for instance if there is an excess of corn ethanol generating D6 RINs), then D6 RINs trade for lower prices than D4 or D5 RINs. If, however, it is difficult for obligated suppliers to meet their renewable fuel obligations due to a shortage of D6 RINs (for example if corn ethanol supply is limited by the blend wall) then the D6 price will rise to meet the prices of other RINs. Figure 21 shows that the relationship between RIN categories has shifted between these two regimes during the past five years. It can be seen that during 2019 D6 RINs traded for on average about 35% of the value of D4 RINs, whereas during 2021 (up to October) they traded for on average 93% of the price of D4 RINs.[14]

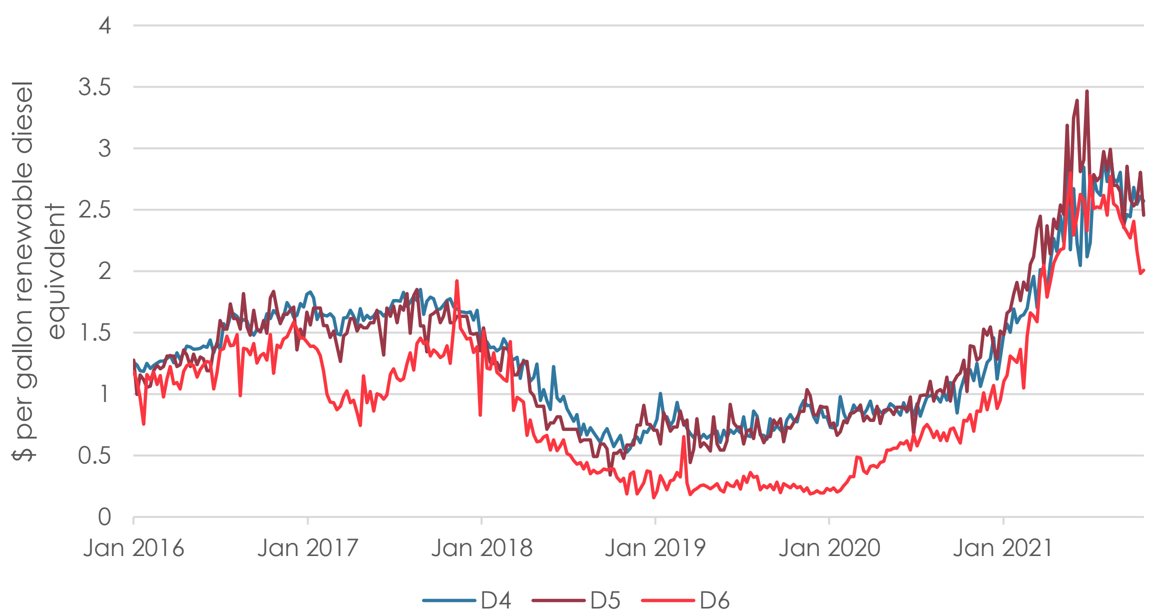

Figure 21. RIN prices in $ per gallon renewable diesel equivalent

Source: U.S. EPA (2021b)

If the price of the D6 RINs were to remain persistently high (above $1 per gallon RDE for example) then this could allow renewable diesel supply to increase beyond the level of the advanced mandate. The non-advanced renewable fuel mandate is set at 8.8 billion gallons

14 Averages taken by weeks, not weighted for number of RINs sold in each trade.

RDE[15] for 2022, and therefore expansion into this part of the market could support a significant fraction of new renewable diesel capacity. The draft impact analysis for the 2022 RFS volume rule (U.S. EPA, 2021a) forecasts that an additional 600 million gallons RDE of renewable diesel will be supplied to make up for a shortfall in corn ethanol supply, bringing total predicted renewable diesel supply to 1.6 billion gallons RDE in 2022 (biodiesel supply is forecast to be more or less static).[16]

5.3. Supply more U.S. produced renewable diesel to meet the RFS biomass-based diesel mandate at the expense of reduced imports of renewable diesel

As discussed in section 4.2, the U.S. imports significant quantities of renewable diesel from the Neste facility in Singapore, most of it for supply to the California market. An increasing availability of domestically produced renewable diesel could result in reduced market space for those imports. While reducing imports would seem an obvious way to increase the scope for supply of domestically produced fuel, in practice we would expect imports to continue for as long as there is a market for them. In particular, Neste's imports rely on the value signal that the California LCFS provides for renewable diesel from waste oils and fats, and this signal should remain strong. As we will discuss in chapter 5, U.S. producers of renewable diesel and biodiesel are likely to end up in intense competition for waste oil and fat resources. The Neste facility in Singapore will be somewhat protected from this increased competition because of its more diversified supply chains (Neste's LCFS pathways suggest that they source material from Asia and Australasia, although some feedstock is also shipped from the U.S. to Singapore for processing, cf. Fuels Institute, 2020). There is plenty of opportunity to supply additional renewable diesel in the California market (about 2.5 billion gallons of liquid fossil diesel that could still be displaced according to CARB, 2018), and so as long as the LCFS credit price remains somewhat robust we would expect that imported renewable diesel from waste oils would be competitive in the U.S. market.

If, however, the value signal in California weakens (as has been predicted by CaliforniaCarbon.info, 2021, for example) then domestically produced soy-oil-based renewable diesel may become more competitive than imports. Displacing imports would make up to 300 million gallons of market space available.

5.4. Dispose of increased renewable diesel production by increasing renewable diesel exports

An alternative (or complement) to reducing imports would be to find new export markets for U.S. produced renewable diesel. The European Union and UK have strong renewable fuel markets under the Renewable Energy Directive and Renewable Transport Fuel Obligation respectively, and in the past the U.S. has at times been successful in exporting corn ethanol and soy biodiesel into the EU market. Increasing interest in renewable jet fuel as an aviation decarbonization option may also create new export opportunities. While European markets

15 15 billion gallons ethanol equivalent.

16 Note however that the EPA state that, "this [extra] volume is assumed to be supplied as imported conventional renewable diesel" rather than domestically produced renewable diesel.

are the most promising destination for exports on face value, European legislation includes limits on the use of food-based biofuels for road transport, and food-based biofuels are set to be excluded entirely from meeting EU aviation fuel mandates (European Commission, 2021). This may limit the appetite for soy-based fuels in Europe, while for producers of waste-based fuels the combined value of the California LCFS, RFS and tax credit is likely to remain as appealing a market as Europe. Exporters would also face competition from producers in the EU itself, where the refiners Eni, Total, Neste and Repsol all have significant existing hydrotreating capacity. It is therefore not at all certain that the EU and UK would represent a viable market for U.S. exports. Canada also has some potential as an export market (and as discussed in section 4.3 may already be taking significant volumes of exported material).

Elsewhere in the world there is potential in principle for markets to open up, but in the past most countries outside Europe and North America have been reluctant to impose biofuel mandates where they cannot be supplied with locally produced fuels. Other regions such as China may be as likely to become competitors as markets (S&P Global Platts, 2021a).

5.5. Rationalization of capacity through capacity cancellations, delays or closures

As noted in section 4.7, it is not inevitable that the full number of capacity additions to the renewable diesel market that have now been announced will actually be built. For example, Stratas Advisors (2020) suggests that a 400-million-gallon investment by Valero in Port Arthur may be reconsidered given potential for overcapacity, while S&P Global Platts (2021b) report that CVR Energy are delaying a planned hydrocracker conversion due to high feedstock costs. Given the tension in the feedstock market, the lack of certainty about the direction of the RFS mandate beyond 2022 and the limited number of export options for U.S. producers, it is possible to be quite confident that more of the announced capacity additions will be delayed or cancelled. It is rather more difficult, however, to predict exactly how much capacity will be realized.

Above, we noted that delivering production of 2.5 billion gallons of fuel, half of the potential capacity identified for 2024 by the EIA, would require 7.6 million tonnes of feedstock. In Chapter 5 we reviewed options for making feedstock available and found that achieving such additional volumes would be exceedingly difficult, and would probably require relying very heavily on imports and a very significant reduction in biodiesel production. To summarize the discussion in Chapter 5 and the rest of Chapter 6, by 2025 it might be possible to deliver up to the following increases in renewable diesel production (assuming that adequate) policy support is available):

- 150 million gallons from additional processing of waste and residual oils and fats;
- 300 million gallons from additional soy oil production in the U.S.;
- 100 million gallons of additional fuel from waste oils and fats by reducing exports and a further 100 million gallons by increasing imports;
- 500 million gallons by eliminating the production of biodiesel from waste oils and fats;
- 250 million gallons by increasing net U.S. vegetable oil imports by 900 thousand metric tons.

This would bring total U.S. production of renewable diesel to about 2 billion gallons a year, and we would consider this a high-end estimate for what might be delivered in reality without causing very strong market distortions[17]. It would imply an increase by 3.3 million metric tons in the consumption of oils and fats for biomass-based diesel production. Assuming an average two thirds capacity utilization (similar to the current capacity utilization rate estimated in section 4.5.8), this would be consistent with 3 billion gallons of total renewable diesel production capacity in 2025, which is close to the projection by Singh & Turaga (2021) that we discussed in section 4.7. That would mean 2 billion gallons of already announced capacity additions being delayed, cancelled or downsized.

17 Recognizing that each of the outcomes listed would still have some distortive effect on other markets.

6. Environmental and climate impacts of HVO production

While renewable fuel policies such as the RFS, LCFS and CFP are intended to contribute to climate change mitigation, there is uncertainty and therefore controversy about whether renewable diesel makes a significant contribution to reducing net emissions when indirect emissions effects are considered. This is especially true for renewable diesel from virgin vegetable oils, but the true net climate benefit is also a concern even for waste and residual oils and fats, when using them for renewable diesel displaces them from other markets. These concerns are well recognized by the EPA and have formed an important part of the context discussed for not increasing advanced biofuel mandates under the RFS above statutory levels in recent volume rules (U.S. EPA, 2019, 2021a). Figure 22 shows ILUC emissions estimated by U.S. regulators for renewable diesel produced from vegetable oils.

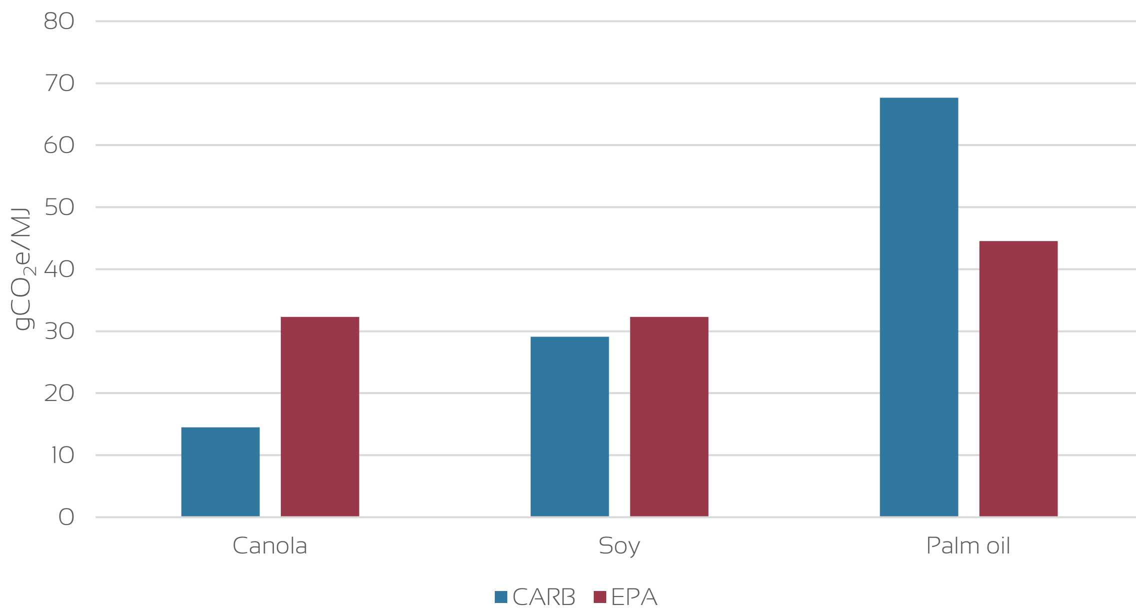

Figure 22. Estimated ILUC emissions from vegetable oil-based fuels

Source: CARB (2014); U.S. EPA (2010, 2011). Note: EPA palm oil ILUC estimate comes from a proposed rule that has not been finalized.

Palm oil expansion, especially in Indonesia and Malaysia, is associated with deforestation in tropical forests and the drainage of peat soils, both of which can result in the loss of large carbon stocks. Analysis for the European Commission suggests that 45% of new oil palm area globally is associated with deforestation, and a further 23% with peat drainage (European Union, 2019). As was shown in Figure 17, increased vegetable oil imports may have played a significant role in supporting the development of the U.S. biodiesel industry, and these increased imports have been split roughly 50:50 between canola oil and palm oil (see Figure 19).

In the 'supply sketch' that we provided at the end of the previous chapter, we suggested that U.S. vegetable oil imports might increase by 900 thousand metric tons to support increased renewable diesel production. If half of this increase in imports (450 thousand metric tons) came from palm oil producers then that would require 125 thousand hectares of oil palm plantations, at a typical palm oil yield of 3.6 metric ton per hectare. If the area of oil palm were to expand by 125 thousand hectares to supply this palm oil, then based on the European Commission analysis mentioned above one might expect this to be associated with 56 thousand hectares of deforestation and 29 thousand hectares of peat loss.

In practice, we would not expect this amount of deforestation to be caused. As has been discussed extensively in the literature on ILUC, one would expect part of the palm oil supply response to be delivered by increasing yields, and expect the supply response to be muted by a reduction in consumption of palm oil for food. Nevertheless, even if half or less of this amount of palm oil were to be delivered by area expansion, it could still be associated with tens of thousands of hectares of forest loss, with accompanying carbon emissions and biodiversity impacts.

Looked at globally, the soybean crop is also associated with tropical deforestation, especially in South America (Malins, 2020). There is no evidence of a strong link between soy expansion and deforestation in the United States, but if exports of soy oil from the U.S. were reduced this could indirectly drive increased supply in other regions.

Currently, the RFS, LCFS and CFP assume that there are no ILUC emissions associated with the use of waste or residual oils (UCO, DCO, animal fats). Not being attributed any indirect emissions is one of the reasons why these fuels achieve lower carbon intensities and higher value in the California and Oregon markets. When these materials have existing productive uses, however, displacing them can be expected to cause indirect demand increases. For example, O'Malley et al. (2021) argues that additional extraction of DCO from distillers' grains is likely to lead to increased demand for cereal feeds while displacing DCO from existing swine and poultry feed markets is likely to lead to increased demand for virgin vegetable oils. Given that such displacement emissions are likely for many of these lower value oils, the overall environmental impact of targeting these resources may be understated in current regulations (Malins, 2017b). The fundamental issue for all renewable diesel production pathways is that oils and fats are valuable resources – even the inedible ones – and that the global supply is limited. There is a very real risk that adding excess pressure to the vegetable oil market in the name of renewable energy policy will drive agricultural expansion that causes significant land use change carbon emissions.

7. Discussion

The biofuel industry in the U.S. and globally is again at a point of transition. Despite concerns about the environmental sustainability and scalability of converting large volumes of oils and fats into fuel, production capacity for hydrotreated renewable diesel and jet fuel is rapidly expanding not only in the U.S. but globally. Achieving the 5 billion gallons of renewable diesel production that have been announced for completion by 2024, without closing down biodiesel plants, would require an increase of 7.6 million metric tons in the commitment of oils and fats to biofuel use. That is equivalent to more than half of the vegetable oil currently consumed for food in the U.S. and would be unachievable without major market distortions and large increases in vegetable oil imports.

We have argued in this report that it is not realistic to believe that the announced rate of expansion of renewable diesel capacity will be delivered – it seems inevitable that some of the announced expansions will be delayed or cancelled. It also unrealistic to believe that even a reduced rate of expansion will be delivered without impacting the biodiesel industry. So long as state programs like the California LCFS and the Oregon CFP make it significantly more profitable to supply waste-oil-based renewable diesel in these states (above the biodiesel blend wall) than to supply waste-oil-based biodiesel in other states, biodiesel producers will struggle to compete for these feedstocks with an expanding renewable diesel industry. We have discussed the possibility that waste-oil-based biodiesel may be more or less eliminated over the next four years if the economics remain as they currently are.

The potential for state low carbon fuel standards to drive feedstock displacement out of other state markets in this way raises important questions for these programs. There is little if any net climate benefit for pulling waste oils out of existing markets and into the West Coast. If the primary impact of this is to result in the closure of an existing industry to allow the creation of a new one, it is not clear that this truly contributes to higher level climate objectives. It may be appropriate for the states with low carbon fuel standards to consider whether the contribution of renewable diesel should be capped to manage the potential for market distortion.

There are also broader unresolved questions about whether increasing the use of oils and fats for fuel is really sustainable in terms of its impact on food markets and the potential to drive further deforestation. We have discussed in this report that there is a risk that expanding renewable diesel production in North America could drive expansion of palm oil in Southeast Asia, and that without dealing with ongoing deforestation in that region there is a risk that this could cause net carbon emissions rather than savings. With a long-term view, considering the need to develop sustainable fuels for aviation as well as for on-road use, we could ask whether the current boom in vegetable oil hydrotreating has become a distraction from the commercialization of the cellulosic biofuel pathways that the RFS was originally intended to support.

Cellulosic drop-in biofuels have greater long-term scalability and GHG reduction potential, and as they rely on lower value resources they have the potential to be a cheaper solution if operating costs can be brought down over time.

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