CALENDAR FOR THE BOARD OF SUPERVISORS
CONTRA COSTA COUNTY
AND FOR SPECIAL DISTRICTS, AGENCIES, AND AUTHORITIES GOVERNED BY THE BOARD
BOARD CHAMBERS, ADMINISTRATION BUILDING, 1025 ESCOBAR STREET
MARTINEZ, CALIFORNIA 94553-1229

KAREN MITCHOFF, *CHAIR,* 4TH DISTRICT
FEDERAL D. GLOVER, *VICE CHAIR,* 5TH DISTRICT
JOHN GIOIA, 1ST DISTRICT
CANDACE ANDERSEN, 2ND DISTRICT
DIANE BURGIS, 3RD DISTRICT

MONICA NINO, CLERK OF THE BOARD AND COUNTY ADMINISTRATOR, (925) 655-2075

PERSONS WHO WISH TO ADDRESS THE BOARD DURING PUBLIC COMMENT OR WITH RESPECT TO AN ITEM THAT IS ON THE AGENDA, MAY BE LIMITED TO TWO (2) MINUTES.
A LUNCH BREAK MAY BE CALLED AT THE DISCRETION OF THE BOARD CHAIR.

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Persons who wish to address the board during public comment or with respect to an item on the agenda may comment in person or may call in during the meeting by dialing **888-278-0254** followed by the access code **843298#.** A caller should indicate they wish to speak on an agenda item, by pushing "#2" on their phone. Access via Zoom is also available using the following link: https://cccounty-us.zoom.us/j/87344719204. Those participating via Zoom should indicate they wish to speak on an agenda item by using the “raise your hand” feature in the Zoom app. To provide contact information, please contact Clerk of the Board at clerkoftheboard@cob.cccounty.us or call 925-655-2000.

Meetings of the Board are closed-captioned in real time. Public comment generally will be limited to two minutes. Your patience is appreciated. A Spanish language interpreter is available to assist Spanish-speaking callers.

A lunch break or closed session may be called at the discretion of the Board Chair.
Staff reports related to open session items on the agenda are also accessible online at **www.contracosta.ca.gov.**

ANNOTATED AGENDA & MINUTES
May 3, 2022

8:30 A.M. Convene, call to order and opening ceremonies.

Closed Session
A. PUBLIC EMPLOYEE PERFORMANCE EVALUATION
Title: County Administrator
B. CONFERENCE WITH LABOR NEGOTIATORS (Gov. Code § 54957.6)
Agency Negotiators: Karen Mitchoff, Federal Glover
Unrepresented employee: County Administrator
Acting as the Board of Commissioners of the Housing Authority of Contra Costa County:
C. PUBLIC EMPLOYEE PERFORMANCE EVALUATION
Title: Executive Director
D. CONFERENCE WITH LABOR NEGOTIATORS (Gov. Code 54957.6)
Agency Negotiators: Karen Mitchoff, Federal Glover
Unrepresented employee: Executive Director

Inspirational Thought- *"Try to be the rainbow in someone's cloud."* ~Maya Angelou

Present: John Gioia, District I Supervisor; Candace Andersen, District II Supervisor; Diane Burgis, District III Supervisor; Karen Mitchoff, District IV Supervisor; Federal D. Glover, District V Supervisor

Staff Present: Monica Nino, County Administrator

Tom Geiger, Deputy County Counsel

Supervisor Burgis did arrive directly following roll call. All Supervisors were present for Closed Session. There were no reports from Closed Session.

CONSIDER CONSENT ITEMS (Items listed as C.1 through C.34 on the following agenda) – Items are subject to removal from Consent Calendar by request of any Supervisor or on request for discussion by a member of the public. **Items removed from the Consent Calendar will be considered with the Discussion Items.**

9:00 A.M.

DISCUSSION ITEMS

D.1 HEARING to consider an appeal of the County Planning Commission's approval of a land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco, to repurpose the Marathon Martinez Refinery for fuel production from renewable sources rather than from crude oil; consider certifying the project environmental impact report, adopting a mitigation monitoring program, findings, and permit conditions, and taking related actions under the California Environmental Quality Act; and consider approving a community benefits agreement related to the project. (Appellant—Natural Resources Defense Council, et al.; Applicant and Owner—Marathon Petroleum Corporation) (Joseph Lawlor, Department of Conservation and Development)

Speakers: Anne Alexander, Natural Resources Defense Council, Connie Cho, Citizens for a Better Environment, and Greg (Appellents); Steve Konig;Greg Karras, (Applicant); Julia McGee, Marathon; Donald Horgan, Marathon; Jason Steinberg, Clyde; Mayim Wiens; James Kimball, USW Local 5-Marathon; Jackie Garcia, 350 Contra Costa; Gary Hughes, Biofuelwatch; Jan Warren, Interfaith Climate Action Network; Charles Davidson; Janet Callaghan, Rodeo; Jesse Peralez, Carpenters Local xx; Lisa Jackson, 350 Contra Costa; Mike Cordy, Rodeo; Emily Hopkins, ICAN; O.G. Strogatz, 350 Contra Costa Acttion; Janet Pygeorge, Rodeo Citizens Association; Caller 6770; Name Not Given; Bill Whitney; Tom Hanson, IBEW Loca 32; Woody Hastings, Climate Center; Marti Roach; Ken Miller, Iron Workers Local 378; Nick Weathers, Northwest Regional Many Helmets to Hardhats; Cynthia Mahoney, M.D.; Clair Brown; Lisa Chang, M.D.; Chuck Leonard Plumbers & Steamfitters Local 342; Fernando C. Laborers Local 324; Andrew Meredith, State Building & Construction Trades Council of California; Stephanie; Liz Ritchie, Timothy Jeffries, Boilermakers Local 549; Theresa Foglio-Ramirez.

Written commentary received on this matter attached.

CLOSED the hearing;
CERTIFIED that the Environmental Impact Report (EIR) for the Martinez Refinery Renewable Fuels Project (State Clearinghouse #2021020289) was completed in compliance with the California Environmental Quality Act (CEQA), was reviewed and considered by the Board of Supervisors before project approval, and reflects the County's independent judgment and analysis;
CERTIFIED the EIR prepared for the Martinez Refinery Renewable Fuels Project;
ADOPTED the CEQA findings for the Project; ADOPTED the Mitigation Monitoring and Reporting Program for the Project;
ADOPTED the statement of overriding considerations for the Project;
DIRECTED the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk;
SPECIFIED that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based;

DENIED the appeal of Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County;
APPROVED the Martinez Refinery Renewable Fuels Project. (Permit No. CDLP20-02046);
APPROVED the findings in support of the Project;
APPROVED the Project conditions of approval;
APPROVED the Community Benefits Agreement;
DIRECTED the addition of a Condition of Approval:

> ***The owner/operator shall ensure that refinery does not process more than 48,000 barrels of renewable feedstock per day combined, based on a rolling 365 day average.***
>
> ***To determine compliance with the above condition(s), the owner/operator shall maintain the following records and provide all of the data necessary to evaluate compliance, including, but not necessarily limited to, the following information: On a daily basis, type and amount of renewable feedstock processed.***
>
> ***These records shall be kept on-site for at least 5 years. All records shall be recorded in an BAAQMD approved log and made available for inspection by County staff upon request. These recordkeeping Requirements shall not replace the recordkeeping Requirements contained in any applicable BAAQMD Regulations.***

and DIRECTED the addition of a Condition of Approval : ***Applicant shall use its best good faith efforts to investigate and use organic waste from local sources as feedstock at the facility.***

Representative of Marathon verbally confirmed agreement with the Community Benefit Agreement and the additional Conditions of Approval.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

D.2 HEARING to consider an appeal of the County Planning Commission's approval of a land use permit for the Phillips 66 Rodeo Renewed Project at 1380 San Pablo Ave in Rodeo, to repurpose the Phillips 66 Rodeo Refinery for fuel production from renewable sources rather than from crude oil; consider certifying the project environmental impact report, adopting a mitigation monitoring program, findings, and permit conditions, and taking related actions under the California Environmental Quality Act; and consider approving a community benefits agreement related to the project. (Appellants—Natural Resources Defense Council, et al.; Charles Davidson; Crockett Community Foundation; Applicant and Owner—Phillips 66 Company) (Gary Kupp, Department of Conservation and Development)

Speakers: Anne Alexander, Natural Resources Defense Council; Connie Cho, Citizens for a Better Environment;Greg Harris (Appellants); Charles Davidson (Appellant); Brian Montgomery, Crockett Commnity Foundation (Appellant); Richard Harbison, VP Phillips 66 Refinery (Applicant); Greg Feere, VP California Building Trades Council; Michael Cody, Rodeo; Tim Johnson, Schultz; Tyson Bagley, United Steelworkers Local 326; Gurant Murdock, Crockett Community Services District; Anthony Hodge, New Horizons; Janet Callaghan; Gary Hughes, Biofuelwatch; Janet Pyegeorge, Rodeo Citizens Association; Jan Warren, Interfaith Climate Action Network; Jesse Peralez, Local 152, Carbcutters 152; Jackie Garcia, 350 Contra Costa; Christine Cody, Rodeo; Michael Kirker, Director Rodeo Community Services District; Charles Miller, Superintendent, John Swett School District; Maureen Brennan, Rodeo; Teresa Foglio-Ramirez, Rodeo Shoshanna, Sunflower Alliance.
Written commentary received is attached.

ADOPTED the recommendations with the addition of the following Conditions of Approval:

> **The owner/operator shall ensure that refinery doesn't exceed these limits:**

* cannot input more than 80,000 arrels of renewable feedstock per day, combined, based on a rolling 12 month period to the pretreatment unit
* cannot process more than 67,000 bpd of renewable fuels

To determine compliance with the above conditions, the owner/operator shall maintain the following records and provided all the data necessary to evaluate compliance, including but not necessaryl limited to, the following information: On a dailey baisis, type and amount of renewable feedstock processed.

These records shall be kept on-site for at least 5 years. all records shall be recorded in an BAAQMD approve log and made available for inspections by County staff upon requiest. Thes recordkeeping Requirements shall not replace the recordkeeping Requirements containe in any applicable BAAQMD Regulations.

Representative of Phillips 66 verbally confirmed agreement with the Community Benefit Agreement and the additional Conditions of Approval.

D. 3 CONSIDER Consent Items previously removed.

There were no items removed from consent for discussion.

D. 4 PUBLIC COMMENT (2 Minutes/Speaker)

Gary, Vice President of an HOA in Contra Costa, believes that Contra Costa is not enforcing fire safety laws.. He noted that there is only one person to do the inspections in his area that are required by law. He said that now building efficient standard requires new construction to include solar energy that generates enough power to offset the annual usage;

Liz Ritche read into the record portions of a letter known as Preservation Paper and Electronic Evidence that she says was sent to the Elections Office of each county. Ms. Ritchie will send a copy to the Board via email;

Name not given, commended the Board for completing today's very long hearings and advised that in the que for telephone callers some calls appeared to drop.

D. 5 CONSIDER reports of Board members.

There were no items reported today.

Closed Session

There were no announcements from Closed Session.

ADJOURN

Adjourned today's meeting at 3:50 p.m.

CONSENT ITEMS

Road and Transportation

C. 1 ADOPT Resolution No. 2022/132 approving and authorizing the Public Works Director, or designee, to fully close a portion of Bixler Road between Echo Place and Balfour Road, and Point of Timber Road east of Poe Drive, on June 14, 2022 through August 2, 2022 from 7:00 a.m. through 5:00 p.m., for maintenance on existing Pacific Gas and Electric Company natural gas line system, Byron area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 2 ADOPT Resolution No. 2022/141 approving and authorizing the Public Works Director, or designee, to fully close a portion of Springbrook Road between Gilmore Court and Sherwood Way, on June 1, 2022 through September 1, 2022 from 7:00 a.m. through 5:00 p.m., for installation of East Bay Municipal Utility District water main and accompanying infrastructure, Walnut Creek area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 3 ADOPT Traffic Resolution No. 2022/4520 to prohibit stopping, standing, or parking on a portion of Arlington Boulevard, as recommended by the Public Works Director, East Richmond Heights area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 4 APPROVE and AUTHORIZE the Public Works Director, or designee, to execute a reimbursement agreement with IPT Richmond DC III LLC in the amount of $267,950 for offsite roadway improvements that serve developments within the North Richmond Area of Benefit, North Richmond area. (100% North Richmond Area of Benefit Funds)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 5 ADOPT Resolution No. 2022/149 accepting as complete the contracted work performed by Sposeto Engineering, Inc., for the 2021 Countywide Curb Ramp Project, as recommended by the Public Works Director, Countywide. (100% Local Road Funds)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Engineering Services

C. 6 ADOPT Resolution No. 2022/138 approving the thirteenth extension of the Subdivision Agreement for subdivision SD06-09131, for a project being developed by Jasraj Singh & Tomas Baluyut, as recommended by the Public Works Director, Bay Point area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 7 ADOPT Resolution No. 2022/142 accepting for recording purposes only an Offer of Dedication for Roadway Purposes for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 8 ADOPT Resolution No. 2022/143 approving the Parcel Map and Subdivision Agreement for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Honors & Proclamations

C. 9 ADOPT Resolution No. 2022/147 proclaiming May 2022 as "Bike to Wherever Days" and May 20, 2022 as "Bike to Work Day," as recommended by the Conservation and Development and Public Works Department Directors. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 10 ADOPT Resolution No. 2022/166 recognizing El Cerrito Fire Chief Michael Pigoni for his 40 years of service, as recommended by Supervisor Gioia.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Appointments & Resignations

C. 11 APPOINT David Yuers to Seat 2 and Anthony Geisler to Seat 3 on the Historical Landmarks Advisory Committee for terms ending August 12, 2022, as recommended by the Contra Costa County Historical Society.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 12 REAPPOINT Philip Leiber to the Category 2 Seat, a statutory member representing legislative bodies of the special districts in the County, on the Treasury Oversight Committee for a term ending April 30, 2026, as recommended by the Treasurer-Tax Collector.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Appropriation Adjustments

C. 13 Health Services (0450)/ISF Fleet Services (0064): APPROVE Appropriation and Revenue Adjustment No. 5045 authorizing the transfer of appropriations in the amount of $60,842 from the Public Health Senior Nutrition Program (0450) to the General Services - Fleet Operations (0064) for the purchase of a vehicle for the Senior Nutrition Program. (100% Federal Older Americans Act)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Personnel Actions

C. 14 ADOPT Position Adjustment Resolution No. 25931 to add one part-time (20/40) Deputy District Attorney - Advanced (represented) position, add one part-time (20/40) Deputy District Attorney - Basic (represented) position and cancel one full-time vacant Deputy District Attorney - Advanced (represented) position in the District Attorney's Office. (100% General Fund)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 15 ADOPT Position Adjustment Resolution No. 25922 to add one Workers' Compensation Claims Adjuster I (represented) in Risk Management. (Cost savings)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Grants & Contracts

APPROVE and AUTHORIZE execution of agreements between the County and the following agencies for receipt of fund and/or services:

C. 16 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with the California Department of Public Health, Tuberculosis Control Branch, to increase the amount payable to the County by $5,000 to a new amount of up to $309,417 with no change in the original term of July 1, 2021 through June 30, 2022, and AUTHORIZE the Purchasing Manager to procure gift cards and vouchers for food, shelter, incentives and enablers (FSIE) totaling up to $5,000 to meet the FSIE needs of Tuberculosis Control Program patients. (No County match)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 17 ADOPT Resolution No. 2022/152 approving and authorizing the Sheriff-Coroner or designee, to apply for and accept a California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant in an initial allocation of $467,210 for the abatement of abandoned vessels and the vessel turn in program on County waterways for the period beginning October 1, 2022 through the end of the grant funding availability. (90% State, 10% County in-kind match)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 18 APPROVE and AUTHORIZE the Health Services Director, or designee, to accept a grant award from the State of California Health and Human Services Agency, California Department of Public Health, to pay the County an amount up to $895,271 for the California Equitable Recovery Initiative to address COVID-19 health disparities among populations at high-risk and underserved communities for the period September 1, 2021 through June 30, 2023. (No County match)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

APPROVE and AUTHORIZE execution of agreement between the County and the following parties as noted for the purchase of equipment and/or services:

C. 19 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with Elior, Inc. (dba Trio Community Meals, LLC), to modify the rate schedule for additional meal services for the County's Senior Nutrition Program with no change in the payment limit of $4,694,071 or term July 1, 2021 through June 30, 2022. (41% Meals on Wheels, 30% Federal Title C-2, 23% Federal Title C-1, 6% Federal and State emergency funds)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 20 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with WestCare California Inc., to increase the payment limit by $168,416 to a new payment limit of $2,092,935 to continue providing substance use disorder prevention, treatment and detoxification services for West Contra Costa County residents with no change in the term July 1, 2021 through June 30, 2022. (100% Assembly Bill 109)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 21 APPROVE and AUTHORIZE the Employment and Human Services Director, or designee, to execute a contract amendment with Planet Technologies, Inc. to increase the payment limit by $215,000 to a new payment limit $314,000, and to extend the term from August 1, 2022 through August 1, 2023 to upgrade the department-wide communication system known as STARS (Shared Text Automated Retrieval System). (51% State, 44% Federal, 5% County)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 22 AWARD and AUTHORIZE the Public Works Director, or designee, to execute a construction contract with Kerex Engineering, Inc., in the amount of $1,698,315 for the 2022 Countywide Curb Ramp Project, Rodeo, Pacheco, Walnut Creek, and Bay Point areas. (100% Local Road Funds)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 23 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract with Bach-Kim Nguyen, O.D. (dba Walnut Creek Optometry Group), in an amount not to exceed $225,000 to provide optometric services to Contra Costa Health Plan (CCHP) members for the period April 1, 2022 through March 31, 2025. (100% CCHP Enterprise Fund II)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 24 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with Ujima Family Recovery Services, to modify the rates for outpatient treatment services for pregnant and parenting women and their young children, with no change in the payment limit of $3,273,091 or term July 1, 2021 through June 30, 2022. (78% Drug Medi-Cal, 10% Substance Abuse Prevention and Treatment Perinatal Set-Aside, 9% Substance Abuse Prevention and Treatment Block Grant, 3% Assembly Bill 109)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 25 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with Bi-Bett, to modify the rates for residential treatment for substance use disorder treatment services for county residents referred through the Behavioral Health Access Line with no change in the payment limit of $5,232,481 or term July 1, 2021 through June 30, 2022. (71% Federal Medi-Cal, 25% Assembly Bill 109, 4% Substance Abuse Treatment and Prevention Block Grant)

AYE: District I Supervisor John Gioia, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Other: District II Supervisor Candace Andersen (RECUSE)

C. 26 APPROVE and AUTHORIZE the Health Services Director, or designee, to execute a contract amendment with J Cole Recovery Homes, Inc., to modify the rates for residential substance abuse use disorder treatment services for male offenders in East Contra Costa County with no change in the payment limit of $934,893 or term July 1, 2021 through June 30, 2022. (30% Local, 29% Federal Drug Medi-Cal, 29% State, 12% Assembly Bill 109)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 27 Acting as the governing body of the Crockett-Carquinez Fire Protection District, APPROVE and AUTHORIZE the Fire Chief, or designee, to execute a contract with Rosenbauer South Dakota, LLC for the manufacture and sale of one 2,000-Gallon Water Tender in an amount not to exceed $310,687. (80% Crockett Community Foundation Grant, 20% Crockett-Carquinez Fire District)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

Other Actions

C. 28 APPROVE and AUTHORIZE the Auditor-Controller, or designee, to pay $5,337 to SJBH, LLC (dba San Jose Behavioral Health Hospital) for the provision of inpatient psychiatric treatment services for County referred children, adolescents and adults during the month of June 2021. (100% Mental Health Realignment)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 29 AUTHORIZE the Auditor-Controller to issue a refund of overpayment of documentary transfer tax totaling $100,002 to specified parties, as recommended by the Clerk-Recorder. (100% County General Fund)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 30 RECEIVE 2021 Annual Report submitted by the Bay Point Municipal Advisory Council, as recommended by Supervisor Glover.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 31 DECLARE and ACCEPT the results of the April 5, 2022 Special Primary Election 11th Assembly District, as recommended by the Clerk-Recorder and Registrar of Voters.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 32 APPROVE clarification of Board action of February 22, 2022 (Item C.51), which authorized the Health Services Director, or designee, to execute a contract with Bridge Hospice East Bay, LLC, in an amount not to exceed $1,000,000 to provide hospice services for Contra Costa Health Plan members, to reflect to correct term of November 1, 2021 through October 31, 2024. (No fiscal impact)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 33 APPROVE and AUTHORIZE the Purchasing Agent to execute, on behalf of the Sheriff-Coroner, a purchase order with Hammons Supply Company in an amount not to exceed $400,000 for the purchase of custodial supplies and equipment repairs as needed by the three County detention facilities, for the period May 1, 2022 through April 30, 2023. (100% General Fund)

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

C. 34 ADOPT Resolution No. 2022/153 authorizing postponement of the Annual Property Tax Sale approved February 22, 2022 by Board Order C.58, to be delayed an additional month until June 29, 2022, as recommended by the Treasurer-Tax Collector.

AYE: District I Supervisor John Gioia, District II Supervisor Candace Andersen, District III Supervisor Diane Burgis, District IV Supervisor Karen Mitchoff, District V Supervisor Federal D. Glover

GENERAL INFORMATION

The Board meets in all its capacities pursuant to Ordinance Code Section 24-2.402, including as the Housing Authority and the Successor Agency to the Redevelopment Agency. Persons who wish to address the Board should complete the form provided for that purpose and furnish a copy of any written statement to the Clerk.

Any disclosable public records related to an open session item on a regular meeting agenda and distributed by the Clerk of the Board to a majority of the members of the Board of Supervisors less than 96 hours prior to that meeting are available for public inspection at 1025 Escobar Street, First Floor, Martinez, CA 94553, during normal business hours.

All matters listed under CONSENT ITEMS are considered by the Board to be routine and will be enacted by one motion. There will be no separate discussion of these items unless requested by a member of the Board or a member of the public prior to the time the Board votes on the motion to adopt.

Persons who wish to speak on matters set for PUBLIC HEARINGS will be heard when the Chair calls for comments from those persons who are in support thereof or in opposition thereto. After persons have spoken, the hearing is closed and the matter is subject to discussion and action by the Board. Comments on matters listed on the agenda or otherwise within the purview of the Board of Supervisors can be submitted to the office of the Clerk of the Board via mail: Board of Supervisors, 1025 Escobar Street, First Floor, Martinez, CA 94553 or to clerkoftheboard@cob.cccounty.us.

The County will provide reasonable accommodations for persons with disabilities planning to attend Board meetings who contact the Clerk of the Board at least 24 hours before the meeting, at (925) 655-2000. An assistive listening device is available from the Clerk, First Floor.

Copies of recordings of all or portions of a Board meeting may be purchased from the Clerk of the Board. Please telephone the Office of the Clerk of the Board, (925) 655-2000, to make the necessary arrangements.

Forms are available to anyone desiring to submit an inspirational thought nomination for inclusion on the Board Agenda. Forms may be obtained at the Office of the County Administrator or Office of the Clerk of the Board, 1025 Escobar Street, Martinez, California.

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www.contracosta.ca.gov

STANDING COMMITTEES

The **Airport Committee** (Supervisors Karen Mitchoff and Diane Burgis) meets quarterly on the second Wednesday of the month at 11:00 a.m. at the Director of Airports Office, 550 Sally Ride Drive, Concord.

The **Family and Human Services Committee** (Supervisors John Gioia and Candace Andersen) meets on the fourth Monday of the month at 9:00 a.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Finance Committee** (Supervisors John Gioia and Karen Mitchoff) meets on the first Monday of the month at 9:00 a.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Hiring Outreach Oversight Committee** (Supervisors Federal D. Glover and John Gioia) meets quarterly on the first Monday of the month at 10:30 a.m.. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Internal Operations Committee** (Supervisors Candace Andersen and Diane Burgis) meets on the second Monday of the month at 10:30 a.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Legislation Committee** (Supervisors Karen Mitchoff and Diane Burgis) meets on the second Monday of the month at 1:00 p.m. in Room 110, County Administration Building, 1025 Street, Martinez.

The **Public Protection Committee** (Supervisors Andersen and Federal D. Glover) meets on the fourth Monday of the month at 10:30 a.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Sustainability Committee** (Supervisors Federal D. Glover and John Gioia) meets on the fourth Monday of every other month at 1:00 p.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

The **Transportation, Water & Infrastructure Committee** (Supervisors Candace Andersen and Karen Mitchoff) meets on the second Monday of the month at 9:00 a.m. in Room 110, County Administration Building, 1025 Escobar Street, Martinez.

AGENDA DEADLINE: Thursday, 12 noon, 12 days before the Tuesday Board meetings.

Glossary of Acronyms, Abbreviations, and other Terms (in alphabetical order):

Contra Costa County has a policy of making limited use of acronyms, abbreviations, and industry-specific language in its Board of Supervisors meetings and written materials. Following is a list of commonly used language that may appear in oral presentations and written materials associated with Board meetings:

AB Assembly Bill
ABAG Association of Bay Area Governments
ACA Assembly Constitutional Amendment
ADA Americans with Disabilities Act of 1990
AFSCME American Federation of State County and Municipal Employees
AICP American Institute of Certified Planners
AIDS Acquired Immunodeficiency Syndrome
ALUC Airport Land Use Commission
AOD Alcohol and Other Drugs
ARRA American Recovery & Reinvestment Act of 2009
BAAQMD Bay Area Air Quality Management District
BART Bay Area Rapid Transit District
BayRICS Bay Area Regional Interoperable Communications System
BCDC Bay Conservation & Development Commission
BGO Better Government Ordinance
BOS Board of Supervisors
CALTRANS California Department of Transportation
CalWIN California Works Information Network
CalWORKS California Work Opportunity and Responsibility to Kids
CAER Community Awareness Emergency Response
CAO County Administrative Officer or Office
CCCPFD (ConFire) Contra Costa County Fire Protection District
CCHP Contra Costa Health Plan
CCTA Contra Costa Transportation Authority
CCRMC Contra Costa Regional Medical Center
CCWD Contra Costa Water District
CDBG Community Development Block Grant
CFDA Catalog of Federal Domestic Assistance
CEQA California Environmental Quality Act
CIO Chief Information Officer
COLA Cost of living adjustment
ConFire (CCCFPD) Contra Costa County Fire Protection District
CPA Certified Public Accountant
CPI Consumer Price Index
CSA County Service Area
CSAC California State Association of Counties

CTC California Transportation Commission
dba doing business as
DSRIP Delivery System Reform Incentive Program
EBMUD East Bay Municipal Utility District
ECCFPD East Contra Costa Fire Protection District
EIR Environmental Impact Report
EIS Environmental Impact Statement
EMCC Emergency Medical Care Committee
EMS Emergency Medical Services
EPSDT Early State Periodic Screening, Diagnosis and Treatment Program (Mental Health)
et al. et alii (and others)
FAA Federal Aviation Administration
FEMA Federal Emergency Management Agency
F&HS Family and Human Services Committee
First 5 First Five Children and Families Commission (Proposition 10)
FTE Full Time Equivalent
FY Fiscal Year
GHAD Geologic Hazard Abatement District
GIS Geographic Information System
HCD (State Dept of) Housing & Community Development
HHS (State Dept of) Health and Human Services
HIPAA Health Insurance Portability and Accountability Act
HIV Human Immunodeficiency Syndrome
HOV High Occupancy Vehicle
HR Human Resources
HUD United States Department of Housing and Urban Development
IHSS In-Home Supportive Services
Inc. Incorporated
IOC Internal Operations Committee
ISO Industrial Safety Ordinance
JPA Joint (exercise of) Powers Authority or Agreement
Lamorinda Lafayette-Moraga-Orinda Area
LAFCo Local Agency Formation Commission
LLC Limited Liability Company
LLP Limited Liability Partnership
Local 1 Public Employees Union Local 1
LVN Licensed Vocational Nurse
MAC Municipal Advisory Council
MBE Minority Business Enterprise
M.D. Medical Doctor
M.F.T. Marriage and Family Therapist
MIS Management Information System
MOE Maintenance of Effort
MOU Memorandum of Understanding
MTC Metropolitan Transportation Commission
NACo National Association of Counties
NEPA National Environmental Policy Act
OB-GYN Obstetrics and Gynecology
O.D. Doctor of Optometry
OES-EOC Office of Emergency Services-Emergency Operations Center
OPEB Other Post Employment Benefits
OSHA Occupational Safety and Health Administration
PARS Public Agencies Retirement Services
PEPRA Public Employees Pension Reform Act
Psy.D. Doctor of Psychology
RDA Redevelopment Agency
RFI Request For Information
RFP Request For Proposal
RFQ Request For Qualifications
RN Registered Nurse

SB Senate Bill
SBE Small Business Enterprise
SEIU Service Employees International Union
SUASI Super Urban Area Security Initiative
SWAT Southwest Area Transportation Committee
TRANSPAC Transportation Partnership & Cooperation (Central)
TRANSPLAN Transportation Planning Committee (East County)
TRE or **TTE** Trustee
TWIC Transportation, Water and Infrastructure Committee
UASI Urban Area Security Initiative
VA Department of Veterans Affairs
vs. versus (against)
WAN Wide Area Network
WBE Women Business Enterprise
WCCTAC West Contra Costa Transportation Advisory Committee

Contra Costa County

To: Board of Supervisors

From: John Kopchik, Director, Conservation & Development Department

Date: May 3, 2022

Subject: Appeal of Martinez Refinery Renewable Fuels Project (County File No. CDLP20-02046)

RECOMMENDATION(S):

1. OPEN the public hearing on an appeal of a Planning Commission decision to approve a land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in the Pacheco area. (Permit No. CDLP20-02046), RECEIVE testimony, and CLOSE the public hearing.
2. CERTIFY that the Environmental Impact Report (EIR) for the Martinez Refinery Renewable Fuels Project (State Clearinghouse #2021020289) was completed in compliance with the California Environmental Quality Act (CEQA), was reviewed and considered by the Board of Supervisors before project approval, and reflects the County's independent judgment and analysis.
3. CERTIFY the EIR prepared for the Martinez Refinery Renewable Fuels Project.
4. ADOPT the CEQA findings for the Project.
5. ADOPT the Mitigation Monitoring and Reporting Program for the Project.
6. ADOPT the statement of overriding considerations for the Project.
7. DIRECT the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk.
8. SPECIFY that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based.
9. DENY the appeal of Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County.
10. APPROVE the Martinez Refinery Renewable Fuels Project. (Permit No. CDLP20-02046).
11. APPROVE the findings in support of the Project.
12. APPROVE the Project conditions of approval.
13. APPROVE the attached Community Benefits Agreement.

FISCAL IMPACT:

The applicant has paid the necessary application deposit, and is obligated to pay supplemental fees to cover all additional costs associated with the application process.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☐ APPROVED AS RECOMMENDED ☑ OTHER

Clerks Notes: See Addendum

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Joseph Lawlor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: June McHuen, Deputy

cc:

BACKGROUND:

See attachment "Exhibit A" for Background Section.

CONSEQUENCE OF NEGATIVE ACTION:

If the Board of Supervisors affirms the appeal, the County Planning Commission's decision to approve the land use permit for the proposed project will be reversed and the land use permit would be denied.

CLERK'S ADDENDUM

Speakers: Anne Alexander, Natural Resources Defense Council, Connie Cho, Citizens for a Better Environment, and Greg (Appellents); Steve Konig;Greg Karras, (Applicant); Julia McGee, Marathon; Donald Horgan, Marathon; Jason Steinberg, Clyde; Mayim Wiens; James Kimball, USW Local 5-Marathon; Jackie Garcia, 350 Contra Costa; Gary Hughes, Biofuelwatch; Jan Warren, Interfaith Climate Action Network; Charles Davidson; Janet Callaghan, Rodeo; Jesse Peralez, Carpenters Local xx; Lisa Jackson, 350 Contra Costa; Mike Cordy, Rodeo; Emily Hopkins, ICAN; O.G. Strogatz, 350 Contra Costa Acttion; Janet Pygeorge, Rodeo Citizens Association; Caller 6770; Name Not Given; Bill Whitney; Tom Hanson, IBEW Loca 32; Woody Hastings, Climate Center; Marti Roach; Ken Miller, Iron Workers Local 378; Nick Weathers, Northwest Regional Many Helmets to Hardhats; Cynthia Mahoney, M.D.; Clair Brown; Lisa Chang, M.D.; Chuck Leonard Plumbers & Steamfitters Local 342; Fernando C. Laborers Local 324; Andrew Meredith, State Building & Construction Trades Council of California; Stephanie; Liz Ritchie, Timothy Jeffries, Boilermakers Local 549; Theresa Foglio-Ramirez.

Written commentary received on this matter attached.

CLOSED the hearing; CERTIFIED that the Environmental Impact Report (EIR) for the Martinez Refinery Renewable Fuels Project (State Clearinghouse #2021020289) was completed in compliance with the California Environmental Quality Act (CEQA), was reviewed and considered by the Board of Supervisors before project approval, and reflects the County's independent judgment and analysis; CERTIFIED the EIR prepared for the Martinez Refinery Renewable Fuels Project; ADOPTED the CEQA findings for the Project; ADOPTED the Mitigation Monitoring and Reporting Program for the Project; ADOPTED the statement of overriding considerations for the Project; DIRECTED the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk; SPECIFIED that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based; DENIED the appeal of Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County; APPROVED the Martinez Refinery Renewable Fuels Project. (Permit No. CDLP20-02046); APPROVED the findings in support of the Project; APPROVED the Project conditions of approval; APPROVED the Community Benefits Agreement; DIRECTED the addition of a Condition of Approval:

> ***The owner/operator shall ensure that refinery does not process more than 48,000 barrels of renewable feedstock per day combined, based on a rolling 365 day average. To determine compliance with the above condition(s), the owner/operator shall maintain the following records and provide all of the data necessary to evaluate compliance, including, but not necessarily limited to, the following information: On a daily basis, type and amount of renewable feedstock processed. These records shall be kept on-site for at least 5 years. All records shall be recorded in an BAAQMD approved log and made available for inspection by County staff upon request. These recordkeeping Requirements shall not replace the recordkeeping Requirements contained in any applicable BAAQMD Regulations.***

and DIRECTED the addition of a Condition of Approval : *Applicant shall use its best good faith efforts to investigate and use organic waste from local sources as feedstock at the facility.*

Representative of Marathon verbally confirmed agreement with the Community Benefit Agreement and the additional Conditions of Approval.

AGENDA ATTACHMENTS

EXHIBIT A - BACKGROUND SECTION

EXHIBIT B - FINDINGS & COA

EXHIBIT C - MAPS

EXHIBIT D - DRAFT CBA

EXHIBIT E - DEIR (LINK)

EXHIBIT F - FEIR and MMRP (LINK)

EXHIBIT G - PROJECT PLANS

EXHIBIT H - APPEAL LETTER

EXHIBIT I - PRESENTATION

MINUTES ATTACHMENTS

Correspondence Received - 1
Correspondence Received - 2
Correspondence Received - 3

Background Section of May 3, 2022 Staff Report regarding Appeal of the Martinez Refinery Renewable Fuels Project (County File# CDLP20-02046)

INTRODUCTION

This is a hearing on an appeal of the County Planning Commission's decision to approve a Land Use Permit to repurpose the Marathon Martinez Refinery for production of fuels from renewable sources rather than from crude oil.

PROJECT SUMMARY

The project includes a land use permit request to repurpose the Refinery for production of fuels from renewable sources rather than from crude oil. Some existing Refinery equipment would be altered or replaced, and additional new equipment units and tanks would be installed, to facilitate production of fuels from renewable feedstock. Crude oil processing equipment that cannot be repurposed for processing of renewable feedstock would be shut down and removed from the Refinery based on an event-based decommissioning plan. Upon completion of facility changes, the Refinery would process up to approximately 48,000 bpd of fresh renewable feeds and would produce renewable diesel fuel, renewable propane, renewable naphtha, and potentially, renewable aviation fuel. The 48,000-bpd throughput limit is both a physical limit based on the configuration of the facility and a legal limit based on permitting constraints that will be implemented by BAAQMD.

GENERAL INFORMATION

1. General Plan: The project site has Heavy Industry (HI), Water (WA), and Open Space (OS) General Plan land use designations.

2. Zoning: The project site is located in the Heavy Industrial (H-I) and Light Industrial (L-I) Zoning Districts, and Railroad Corridor (-X) Combining District.

3. California Environmental Quality Act (CEQA) Compliance: The Department of Conservation and Development, Community Development Division (CDD) determined that an EIR was required for the project and distributed a Notice of Preparation (NOP) on February 17, 2021.

An Environmental Impact Report (EIR) was then prepared and published for the project (State Clearinghouse #2021020289). The 60-day public review period for the Draft EIR started on October 18, 2021, and closed on December 17, 2021. The Draft EIR is included as an attachment. The County received 251 comment letters during the comment period on the Draft EIR for the proposed project. A Final EIR has been prepared that includes the comments received on the Draft EIR and the County's responses to those comments. The Final EIR also includes associated text changes relating to the comment responses. The Final EIR is included as an attachment to this report.

The EIR for the proposed Project identified significant impacts that cannot be fully mitigated to less-than-significant levels with implementation of identified mitigation measures. These significant and unavoidable impacts include marine biological resources, hazards, hydrology and water quality related to marine vessel accidents, and air quality related to rail and vessel emissions outside the San Francisco Bay Area Air Basin. The EIR also identifies potentially significant impacts related to: construction-related air emissions; odor;

marine and avian biological resources (non-spill related); cultural resources; seismicity; hazards; and tribal cultural resources. However, mitigation measures are identified for these impacts to reduce them to less-than-significant levels. The recommended mitigation measures are included within the Mitigation Monitoring and Reporting Plan, which describes the timing and responsible agency for monitoring compliance with all mitigation measures. The mitigation measures have also been incorporated into the recommended conditions of approval.

4.Tribal Cultural Resources: As required by CEQA and Assembly Bill 52, Contra Costa County submitted a request for formal consultation to the Wilton Rancheria on October 28, 2020. Mariah Mayberry of the Wilton Rancheria responded on November 20, 2020, stating that the tribe had identified cultural resources near the Project's footprint and that the tribe would like to have a monitor present during all ground disturbance activities. The tribal monitor would be required as a condition of project approval. The consultation and monitoring satisfy the consultation requirements under AB 52.

SITE/AREA DESCRIPTION

Surrounding Land Uses: The open waters of the Carquinez Strait and lower Suisun Bay are offshore to the north of the Project site. Onshore, undeveloped lands on and around the Project site include marsh habitats between open water and onshore facilities and ruderal/upland habitat onshore between the marsh habitat and developed lands. Developed lands in the immediate and general vicinity of the Project site include a variety of residential, commercial, industrial, and public uses.

Just east of the Refinery and Avon Marine Oil Terminal (Avon MOT) are several hundred acres of undeveloped marshlands. This area includes the Point Edith Wildlife Preserve, a 761-acre tidal area accessible to the public for wildlife viewing and hunting. The unincorporated residential community of Clyde is east of the Refinery's on-site marshlands, on the opposite side of Port Chicago Highway from the Refinery's eastern property line. The Contra Costa Water District's Mallard Reservoir, and multiple complexes of light industrial warehouse buildings are also located east of the Project site.

The Refinery property's southern boundary adjoins the city of Concord municipal limit at Solano Way. The property's western boundary is as close as 0.25 mile eastward of the city of Martinez municipal limit at the northern end of the Refinery property. Development south of the Project site includes a car dealership, retail and light industrial warehouses, a drive-in movie theater, the Buchanan Airfield, and residential neighborhoods including a community park (Hillcrest). The closest residence in these neighborhoods is approximately 700 feet south of the site's southern property line, in the Dalis Gardens Mobilehome Park. The Floyd I. Marchus school is the closest public school to the site, located approximately 2,900 feet south of the Refinery's southern property line.

Pacheco Creek adjoins the Project site's western property line. Other single-family residential neighborhoods in the city of Martinez are approximately 2,900 feet or further west of the Refinery property's western boundary. Much of the land between the Refinery property and these neighborhoods is undeveloped, though several parcels have industrial land uses including a rock quarry, a concrete batch plant, a waste transfer station, and the treatment plant of the Central Contra Costa Sanitation District. Similarly, lands immediately adjacent to the Amorco Marine Oil Terminal (Amorco MOT) are developed with industrial uses including warehouses and tanks and equipment of the Shell Refinery. The closest non-industrial developments to the Amorco MOT are the public Waterfront Park and single-family residences, both of which are approximately 2,500 feet west and southwest, respectively, of the property line of the terminal.

State Route 4, an east-west freeway, extends through the Project area, south of the Project site and 500 feet south of the Refinery's southern boundary. Interstate 680 is a north-south freeway that extends through the Project area approximately 1.25 miles west of the Refinery's western property line. Both freeways provide regional access to and from the Refinery. On-ramps to and off-ramps from State Route 4 are just southeast of the Refinery's Solano Way entrance, and on-ramps to and off-ramps from Interstate 680 are on Waterfront Road approximately 2 miles west of the site.

Two railroad lines run through the Refinery property: the Union Pacific Railroad (UPRR) line, which runs in an east-west direction through the Refinery along Waterfront Road and the BNSF Railway line, which also runs in an east-west direction through the Refinery, roughly parallel to and north of Monsanto Way.

Site Description: The Marathon Martinez Refinery is located at 150 Solano Way, Martinez, California. The site is situated on the Carquinez Strait, approximately 3.25 miles east of downtown Martinez along Solano Way between Waterfront Road and Monsanto Way. Access to the Refinery is provided from the south via gated entrance on Solano Way and from the west via gated entrance on Waterfront Road.

The Refinery is situated east of Pacheco Creek, on the southern shore of Suisun Bay. The Refinery has marine access through two MOTs on Suisun Bay and the Carquinez Strait, namely the Avon MOT and Amorco MOT. Both MOTs are owned by Andeavor Logistics, LP, also a wholly owned subsidiary of Marathon. The Avon MOT is located on approximately 13.3 acres of leased sovereign land in the lower Suisun Bay, approximately 1.75 miles east of the Benicia-Martinez Bridge, in unincorporated Contra Costa County. The Amorco MOT is located on approximately 14.3 acres of leased sovereign land, approximately 0.6 miles west of the Benicia-Martinez Bridge in the city of Martinez.

The project area is approximately 2,000 acres owned by Marathon. Of these 2,000 acres, approximately 1,130 acres are currently developed for oil and gas refining operations, including ancillary support facilities such as administrative offices, internal roadways and parking lots. The remaining, approximately 870 acres includes undeveloped marshlands and grasslands. Mt. Diablo Creek and Seal Creek flow through the undeveloped areas on the eastern side of the site. Approximately 76 acres at the southern end of the Project site is developed with a complex of recreational baseball, softball and soccer fields that are used by local sports clubs and teams but are part of the property owned by Marathon.

The Amorco MOT is on Assessor's Parcel numbers 378-010-010 and 378-010-030 in the City of Martinez. The Refinery and Avon MOT encompass the following Assessor's Parcels located in unincorporated Contra Costa County: 159-010-005, 159-120-031, 159-130-031, 159-020-001, 159-120-036, 159-140-036, 159-040-048, 159-120-037, 159-260-012, 159-100-008, 159-120-038, 159-260-013, 159-100-028, 159-120-039, 159-260-014, 159-110-030, 159-120-040, 159-270-003, 159-120-001, 159-130-006, 159-270-005, 159-120-006, 159-130-017, 159-270-006, 159-120-007, 159-130-018, 159-280-010, 159-120-009, 159-130-024, 159-280-011, 159-120-016, 159-130-026, 159-280-012, 159-120-018, 159-130-027, 159-290-002, 159-120-019, 159-130-028, 159-120-023, 159-130-029.

PROJECT DESCRIPTION

The proposed Project would repurpose the Refinery for production of fuels from renewable sources rather than from crude oil. Some existing Refinery equipment would be altered or replaced, and additional new equipment units and tanks would be installed, to facilitate production of fuels from renewable feedstock. Crude oil processing equipment that cannot be repurposed for processing of renewable feedstock would be shut down and removed from the Refinery based on an event-based decommissioning plan.

Construction activities would take place within the existing Refinery property. New equipment for the Project would be installed among existing refining equipment in the industrially developed portion of the property. Installation of new equipment or decommissioning of existing equipment not needed for the Project would not require removal of trees or grading of hilly terrain or rock outcroppings because of the location of the equipment within the developed Refinery footprint.

Upon completion of facility changes, the Refinery is anticipated to process up to approximately 48,000 bpd of fresh renewable feedstocks and would produce renewable diesel fuel, renewable propane, renewable naphtha, and, potentially, renewable aviation fuel. Initially, product from the Refinery would be distributed by truck to the Bay Area as well as Central and Northern California. Future regulatory changes may allow the facility to utilize existing petroleum-based product pipelines. Product would also be transported to destinations outside of the Bay Area by ship via the Avon MOT and Amorco MOT. Both terminals would undergo modifications to facilitate receipt of renewable feedstocks and distribution of renewable fuels associated with the proposed Project. Refined petroleum products would continue to be received, stored, and distributed through the Project Site but would not be further processed at the facility.

Marathon anticipates phasing in the project over a period of three years starting in 2022 with a maximum of 23,000 bpd and achieving full production capacity of 48,000 bpd of renewable feedstocks by the end of 2023. The Refinery would continue to operate 24 hours per day, seven days per week, and would be staffed by an estimated 110 workers per day on a rotating shift basis.

Clearing, grading, and other site preparation work would be completed prior to commencement of construction. Equipment to be used in site preparation and demolition for the Project would include lifts, air compressors, industrial saws, cranes, excavators, forklifts, tractors, loaders and welders, as well as light-duty vehicles (passenger cars and trucks) and heavy-duty vehicles (cement, dump and water trucks). Approximately 2.4 acres of grading would be necessary for the proposed Project, with grading limited to 48- to 60-inch-deep trenches to install utilities to new work units and foundations for new units and facilities.

ENVIRONMENTAL REVIEW

The County prepared an Environmental Impact Report (EIR) for the project (State Clearinghouse# 2021020289). The project EIR is composed of both a Draft EIR (Exhibit F) and Final EIR (Exhibit G). The Notice of Preparation (NOP) of the EIR was posted on February 17, 2021, and a public Scoping Meeting was held on March 15, 2021. Both written and oral comments were received during the NOP public comment period and the Scoping Meeting; the comments were responded to in the Draft EIR, which was released for public review on October 14, 2021, with a Notice of Availability. A 60-day comment period for the Draft EIR extended from October 18, 2021, through December 17, 2021. During the comment period, the County received 251 comment letters on the Draft EIR for the proposed project. The comment topics included a wide breadth of concerns from local and state agencies as well as organizations and individuals. The major topics include Project Baseline, CEQA Alternatives, CEQA Cumulative Impacts, Land Use & Feedstock Impacts, and Public Safety. The County's Reponses to the comments received are provided in the Final EIR that has been prepared for certification by the County Board of Supervisors.

The EIR for the proposed project identified six significant and unavoidable impacts related to air quality, biological resources, hazards, and water quality, including:

Air Quality

1. Nitrogen oxides (NOx) emissions from rail traffic in Placer County and marine vessels in the SJVAPCD would exceed significance thresholds, resulting in significant and unavoidable impacts.

2. Though the Project would result in an overall reduction in air emissions from the Refinery, cumulative criteria pollutant health risk (i.e., emissions from the Project plus other development in the vicinity of the Project Site) would continue to exceed regional air quality thresholds of significance, and this impact would remain cumulatively significant and unavoidable.

Biological Resources

3. Adverse impacts to special status species, protected habitats, and migratory corridors and nursery sites for native species as a result of a major spill would remain significant and unavoidable.

4. Adverse impact to special status species, protected habitats, and migratory corridors and nursery sites for native species from introducing new nonindigenous aquatic species via ballast water and vessel biofouling to the San Francisco Bay Estuary waters remains significant and unavoidable.

Hazards and Hazardous Materials

5. Increased vessel calls would increase the potential for corresponding accidental releases of renewable fuel or feedstocks which would be significant and unavoidable.

Water Quality

6. A large spill could still occur and result in impacts on water quality that would be significant and unavoidable.

The County may approve the Project with significant adverse environmental impacts that are not mitigated if it finds that specific economic, legal, social, technological, or other considerations, including provision of employment opportunities for highly trained workers, make imposition of mitigation measures or Project alternatives infeasible. (Public Resources Code Section 21081(a); CEQA Guidelines Section 15091(a)(3).) As noted above, prior to approving the Project with significant unavoidable adverse impacts, the County must also adopt a statement of overriding considerations that economic, legal, social, technological, or other benefits of the project outweigh the significant environmental effects of the project. (Public Resources Code Section 21081(b); CEQA Guidelines Section 15093.) The County can make the requisite findings and adopt the statement of overriding consideration that the potential benefits of the project do in fact outweigh the environmental impacts. The project's benefits include, providing jobs, improving air quality, reducing the amount of hazardous materials in the area, reduction in greenhouse gas emissions, and decrease energy (electricity and natural gas) demand at the facility. The County's findings and statement of overriding consideration are attached to this staff report in the project's findings and proposed conditions of approval.

In addition, other potentially significant impacts were also identified, all of which can be mitigated to a less-than-significant level. These impacts affect the environmental topics of:

- Air Quality
- Biological Resources
- Geology and Soils
- Greenhouse Gas Emissions
- Hazards and Hazardous Materials
- Hydrology and Water Quality

Environmental analysis contained in the EIR determined that measures were available to mitigate these potential adverse impacts to less-than-significant levels. (Public Resources Code Section 21081(a); CEQA Guidelines Section 15091(a)(1).)

As discussed previously, a Final EIR has been prepared that includes the written comments received on the Draft EIR and the County's responses to the comments received. The Final EIR also includes County-initiated updates and errata to the Draft EIR. These errata constitute minor text changes to the Draft EIR and occurred in Chapter 1 Introduction; Chapter 2 Project Description; Chapter 3 Environmental Impact Analysis, Methodology and Baseline, Section 3.3 Air Quality, Section 3.4 Biological Resources, Section 3.5 Cultural Resources, Section 3.8 Greenhouse Gas Emissions, Section 3.9 Hazards and Hazardous Materials, Section 3.10 Hydrology and Water Resources, Section 3.15 Utilities and Service Systems; and Chapter 4 Cumulative Impacts. All changes are identified in chapter 4 of the Final EIR. The changes were made primarily to correct grammatical and typographical errors, as well as to improve accuracy and readability of certain passages. The text changes are not the result of any new significant adverse environmental impact, and do not alter the effectiveness of any mitigation included in the pertinent section, and do not alter any findings in the Draft EIR. Pursuant to CEQA Guidelines Section 15088.5(a), recirculation of a Draft EIR is required only if:

"1) a new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented;

2) a substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance;

3) a feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it; or

4) the draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded."

None of the text edits or changes to the Draft EIR meet any of the above conditions. Therefore, recirculation of any part of the Draft EIR is not required. The information presented in the project EIR support this determination by the County.

Pursuant to CEQA Guidelines Sections 15091 and 15097, a Mitigation Monitoring Program has been prepared, based on the identified significant impacts and mitigation measures in the project EIR. The Mitigation Monitoring Program is intended to ensure that the mitigation measures identified in the EIR are implemented. The Mitigation Monitoring Program is included in Exhibit G herein. All mitigation measures are included in the Conditions of Approval.

STAFF ANALYSIS

1. General Plan Consistency

The Refinery equipment and related structures and facilities are on lands designated by the County General Plan as Heavy Industry (HI). The Avon Terminal, operated under a permit issued by the State Lands Commission, has a County General Plan land use designation of Water (WA). The pipeline between the Avon MOT and the Refinery is within a narrow strip of land designated as Open Space (OS). The City of Martinez General Plan maps the lands at the Amorco Tank Farm adjacent to the Amorco MOT as Industrial. The County General Plan describes the HI, WA and OS land use designations as follows:

Heavy Industry (HI): This designation allows activities requiring large areas of land with convenient truck, ship, and/or rail access. These uses are typically not compatible with residential uses in close proximity and the operations conducted may be characterized by noise or other conditions requiring spatial separation. Uses may include metalworking, chemical or petroleum product processing and refining, heavy equipment operation and similar activities. Light industrial land uses will be allowed within lands designated Heavy Industrial and they can be developed according to light industrial definition and standards found in that designation.

Water (WA): This designation is applied to approximately 68 square miles of water in San Francisco-San Pablo Bay and the portion of the Sacramento-San Joaquin River estuary system which is within the county. The designation is also applied to all large inland bodies of water such as reservoirs. Uses allowed in areas designated Water include transport facilities associated with adjacent heavy industrial plants, such as ports and wharves, and water-oriented recreation uses such as boating and fishing. Construction of new residences or commercial uses and the subdivision of land are inconsistent with this General Plan designation.

Open Space (OS): This land use designation includes publicly-owned open space lands which are not designated as Public and Semi-Public, Watershed, or Parks and Recreation. Lands designated Open Space include, without limitation, wetlands and tidelands and other areas of significant ecological resources, or geologic hazards. The Open Space designation also includes privately-owned properties for which future development rights have been deeded to a public or private agency. For example, significant open space areas within planned unit developments identified as being owned and maintained by a homeowners association fall under this designation. Also included are the steep, unbuildable portions of approved subdivisions which may be deeded to agencies such as EBRPD, but which have not been developed as park facilities. Other privately-owned lands have been designated as Open Space consistent with adopted city general plans.

The most appropriate uses in Open Space areas involve resource management, such as maintaining critical marsh and other endangered habitats or establishing "safety zones" around identified geologic hazards. Other appropriate uses are low-intensity, private recreation for nearby residents. Construction of permanent structures (excluding a single-family residence on an existing legally established lot), not oriented towards recreation or resource conservation, is inconsistent with this designation. One single-family residence on an existing legal lot is consistent with this designation.

Of the approximately 2,000 acres owned by Marathon, approximately 100 acres of undeveloped area east of the Refinery tanks, plus the undeveloped acreage outside and east of the Refinery, are designated Parks and Recreation (PR) and (OS). Approximately 93 acres of the on-site recreational fields is designated Light Industry (LI). No new development on these undeveloped or recreational areas of the property is proposed with the Project.

In addition to the mapped land use designation, County General Plan land use-related policies that are applicable to the proposed Project include the following:

Noise Polices

Policy 11-1 establishes the acceptability of proposed new land uses within existing noise-impacted areas in accordance with the State of California General Plan Guidelines. The maximum exterior noise level considered to be “normally acceptable” for single-family residential uses is 60-dBA Ldn, and noise levels of up to 70-dBA Ldn are considered to be “conditionally acceptable.” The maximum exterior noise level considered to be “normally acceptable,” without condition, for industrial uses is 70-dBA Ldn. This policy does not apply to temporary noise levels, such as from construction. The project is not expected to create noises that would exceed thresholds within surrounding properties.

Policy 11-8 states that construction activities shall be concentrated during the hours of the day that are not noise-sensitive for adjacent land uses and should be commissioned to occur during normal work hours of the day to provide relative quiet during the more sensitive evening and early morning periods. These limitations would be included as conditions of approval.

2. Zoning Consistency

Zoning regulations for the County are adopted into Title 8, Zoning, of the Ordinance Code of Contra Costa County, which provides regulations for development of land in the unincorporated areas and includes by reference in County Code Section 84-2.002 a Zoning Map that assigns a zoning classification to each parcel within the County’s jurisdiction. The Zoning Map classifies the lands on which the Refinery’s equipment and tanks are located as H-I (Heavy Industrial) District. In the H-I District, heavy manufacturing, including but not limited to manufacturing or processing of petroleum, chemicals, lumber, and steel, are permitted uses of land. There are no minimum lot area, maximum height, or minimum setback regulations with which development in the H-I District must comply (County Code Sections 84-62.402 and 84-62.602).

Although fuel production facilities are permitted uses of land in the H-I District, the County Ordinance Code requires land use permits for specified development projects involving hazardous waste or hazardous material as specified in the County’s Industrial Safety Ordinance (County Ordinance No. 98-48).

County Code Chapter 84-63 (Development Projects Involving Hazardous Waste or Hazardous Materials) requires a land use permit for specified development projects involving hazardous waste or hazardous material, based on a “hazard score.” The “hazard score” is determined based on specified factors, including if the development project will result in a new process unit, unless the process unit is otherwise exempt. Other input factors for determining the hazard score include the hazardous material being stored or handled, distance between the facility and the nearest sensitive receptor, size of the facility and transportation risk. As the Project includes the installation of new foundations and equipment units (e.g., pretreatment unit, hydrodeoxygenation units), a land use permit is required.

3. Traffic and Circulation

Normal Project operations would not interfere or conflict with existing transit, roadway, bicycle, or pedestrian activities. Transportation impacts during Project operation would be minimal. During construction, the proposed Project would have the potential to disrupt normal traffic and circulation on roadways and bicycle or pedestrian activities. Designated areas of aboveground construction for the proposed Project are zoned for industrial uses and operate at low traffic volumes and a high level of service under existing conditions. As discussed in Chapter 2, Project Description, of the Draft EIR, initial construction activities for the proposed Project are expected to begin in the second quarter of 2022, and are expected to be completed by 2024. Fuel processing would begin within the first year of construction. The construction activities for most of the components of the proposed Project would be expected to overlap during the Project’s peak construction period. Construction work shifts are expected to last about 10 hours per day during most portions of the construction schedule. During normal construction periods, one work shift per day is expected. During Refinery turnaround periods (when some of the Refinery Units would be shut down), two work shifts are expected and work may be conducted 24 hours per day.

Transportation conditions during construction were analyzed assuming the maximum number of construction trips. The traffic analysis in Section 3.14, Transportation, is based on a construction schedule that presumes a total of 1,400 workers, most working day shifts. During construction, the number of truck trips would be estimated at between 60 and 310 trips per day, depending on timing and phasing. A number of trips would be used for deliveries and distribution of petroleum coke and products manufactured at the Refinery.

Project truck trips would be scheduled to avoid peak travel times along major highways, and full road closures would not be expected. Caltrans began a major construction project in 2019 to modify the Interstate 680 and State Route (SR) 4 interchange configuration, which includes widening approximately four miles of SR 4 in both directions between Morello Avenue in Martinez and SR 242 by adding a third lane in both directions to improve on- and off-ramp merging. It is anticipated that the Caltrans project would be near completion by the initial phases of Project construction and would not overlap with peak Project construction conditions.

Due to the number of employees expected during Project construction, a short-term increase in vehicle trips and construction traffic would last for the duration of construction. The transportation impacts during Project construction would be less than significant. The Project would not require an increase in the number of workers required to operate the Refinery, and no long-term operational traffic impacts would be expected.

Refinery operations would not result in noticeable changes to emergency access or emergency response conditions. Project construction may have the potential to cause temporary traffic disruption and may require the use of alternate traffic routes. Emergency response providers in the vicinity of construction areas would be given advance notice of construction schedules and locations, road closures and possible alternate routes.

4. Drainage and Stormwater Management and Discharge Control

Proposed Project construction activities would be located within the existing Project Site, and Project activities are not expected to result in the construction of additional impervious surfaces that would substantially alter existing drainage patterns. There are no streams, rivers or other natural drainages within the Project Site that would be impacted by the construction of new units or equipment. Stormwater and surface runoff within the Project Site are already treated within the existing wastewater treatment plant and managed under a National Pollutant Discharge Elimination System (NPDES) permit. When Project operations commence, it is expected that the existing NPDES permit would be modified to include the new wastewater treatment equipment and reflect the new characteristics of the wastewater stream. The NPDES permit establishes limits for various contaminants (including oil and grease, biological oxygen demand, pH, whole effluent toxicity and other contaminants such as heavy metals). Wastewater would be required to be discharged in compliance with the NPDES permit. The Refinery wastewater streams from the previous refining operations and most of the stormwater runoff is collected and managed in the existing wastewater treatment system that is regulated by the San Francisco RWQCB under a NPDES discharge permit (Order No. R2-2015- 0033). The existing permit expired in 2020 but has been temporarily extended until an updated permit can be issued that reflects the new operations.

APPEAL OF THE COUNTY PLANNING COMMISSION'S DECISION

A Land Use Permit for the applicant's project was approved by the County Planning Commission on March 23, 2022. Public testimony was taken for and against the project. Commenters raised a number of concerns including adequacy of the project description, accuracy of the baseline evaluation, adequacy of the hazard analysis related to hydrogen, adequacy of food-system-impact review, job creation impacts, emissions impacts, and other issues, both positive and negative, regarding the project implementation. After the close of the hearing, the Planning Commission voted 6-0 to certify the Project environmental impact report and approve the land use permit application.

On March 28, 2022, Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County (Appellants) filed a joint appeal with the Department of Conservation and Development, Community Development Division, over the decision of the County Planning Commission to certify the Project environmental impact report and approve the land use permit. The Appeal presents five general issues:

- The Final Environmental Impact Report (FEIR) fails to disclose information on issues critical to assessing the Project and fails to define and consider appropriate mitigation for significant impacts;
- The FEIR fails to comply with the California Environmental Quality Act (CEQA) requirement to respond to public comments;

- The County Has Made No Findings Concerning Choice of Alternatives and Throughput Volumes;
- The FEIR presents critical information describing the Project for the first time; and
- The Statement of Overriding Considerations unlawfully purports to override significant impacts that could have been feasibly mitigated.

The Appeal then notes specific comments on the content of the FEIR, with reference to the general issues above regarding impact assessment, mitigation measures, responses to comments, Project information, and the Statement of Overriding Considerations. Staff has prepared the following response to the Appeal to addresses those specific comments, as listed in the Appeal under the headings quoted below (for clarity, specific comments under the Appeal headings are enumerated).

I. Appellants contend: “The Decision to Certify the FEIR is Contrary to Law and Not Supported by Substantial Evidence”

(a) Project description

The Appeal states that the Project Description does not identify “hydroprocessed esters and fatty acids” (HEFA) as the technology that will be utilized by the proposed Project during refining of renewable feedstocks. This appeal point is without merit because the project description does identify the proposed processes in sufficient detail and adequate under CEQA Guidelines 15124(c).

CEQA Guidelines Section 15124(c) states that a Project Description should provide “a general description of the project’s technical, economic, and environmental characteristics…” Information regarding refinery operations was included in the DEIR in Section 2.5, Project Operations and Table 2-1: Refinery Equipment Modifications, which includes a description of how refinery equipment would be used during operations. As provided, the key components of the proposed renewable fuels processing – the use of hydrotreaters, the use of hydrogen, and the use of vegetable oils or animal fats – are described. This information provided the basis for the impact analysis conducted in the DEIR. In response to comments from the public on the DEIR regarding safety concerns, in particular air quality impacts from flaring, Master Response 5: Public Safety (pages 3-37 to 3-43 of the FEIR) provides additional details to clarify the information provided in the DEIR on refinery operations. The response clarifies that “HEFA” is the technical name of the refining process for renewable feedstocks that is described in Section 2.5 and Table 2-1.

CEQA Guidelines Section 15140 state that “EIRs shall be written in plain language … so that decision makers and the public can rapidly understand the documents.” The term “HEFA” is technical and non-descriptive— not ‘plain language.’ Its use in Master Response 5 of the FEIR was in response to its use by the Appellant in their comments on the DEIR. It was unnecessary to use the term in the Project Description of the DEIR; as acknowledged by the Appellant in their DEIR Comment at O12-24, which states "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." Therefore, the information provided in Section 2.5, Project Operations and Table 2-1: Refinery Equipment Modification of the DEIR was of sufficient detail for Appellants to identify the processing technology by name as HEFA.

No new or additional potentially significant environmental impacts arise from identifying the refining process as “HEFA” in the FEIR, nor does it change either the type of environmental impacts arising from the project or their severity. All materials and processes for the refining of renewable feedstocks were evaluated in as much detail as necessary to discern the potential impacts of the project. Therefore, the Project Description is adequate under CEQA Guidelines 15124(c).

(b) Baseline

The Appeal states that the FEIR did not respond to evidence that Refinery closure since April 2020 is permanent and is related to Marathon’s consolidation of operations and to market conditions. The Appeal states that Marathon’s maintenance of various permits for Refinery operation is related to the Avon and Amorco marine oil terminals (MOTs) which would continue operations to serve Project feedstock shipments. The Appeal restates the comments on the DEIR, that the CEQA baseline should be non-operation of the Refinery, and that this would require analysis of Project impacts against that baseline. This appeal point is without merit because the FEIR provides and thorough description of the selected baseline, including the basis for its selection and that selection’s compliance with CEQA Guidelines Section 15125, and relevant case law.

FEIR Chapter 3, Section 3.1.1, Master Response 1: CEQA Baseline, addresses those issues. The section titled “Petroleum Processing at the Refinery,” pages 3-4 to 3-10, acknowledges the market trends in the comments on the DEIR, but concludes that “[w]hile the data in the comments indicate recent trends, the conclusion that Marathon would not re-start petroleum processing at this specific site is speculative” (page 3-5); Master Response 1 continues and presents specific data on crude, diesel, jet fuel, and gasoline consumption in California that supports continued petroleum refining. The FEIR concludes, on page 3-9, that:

“Upon review of the data from the CEC and U.S. EIA, the demand for petroleum-based products appears to support the continued operation of the Refinery should the Project not be implemented. Furthermore, Marathon has continued to comply with all regulatory requirements and maintain all permits necessary for crude oil refining, providing a path for continued operations if the Project is not implemented. Therefore, as presented in this Master Response, the Draft EIR definition of the baseline condition is accurate, and Marathon maintains a feasible option to re-start petroleum process at the Refinery.”

The FEIR further supports the conclusion of continued crude feedstock processing by describing the maintenance of permits. Master Response 1: CEQA Baseline, FEIR page 3-4 states:

“Though Refinery operations are currently suspended, Marathon has the option of restarting petroleum processing at the Refinery. Marathon has continued to comply with all regulatory requirements and maintain all permits necessary for crude oil refining. For example, the Refinery has maintained and updated all air permits for operation as an oil refinery and has maintained its Standard Industrial Classification (SIC) code as an oil refinery, which triggers regulatory requirements with which the Refinery continues to comply. Table 3-1, Current Permits to Operate Martinez Refinery lists those permits. Based on this information, there is no basis for expecting that operations would cease indefinitely, and the use of the 5-year baseline correctly captures fluctuations (even zero production) in the product manufacturing facility."

As stated by the Appellants, the permits listed in Table 3-1 do, in part, relate to operation of the Avon and Amorco MOTs, and this permit maintenance is necessary for the future use of the facility for renewable feedstocks, and current petroleum storage and transfer operations. But maintenance of these MOT-related permits would also be required for resumed petroleum refining operations, and supports the conclusion that the refinery could continue to process crude feedstocks because the terminals and associated vessel call limits are adequate and necessary for the importation of crude for petroleum refining. Furthermore, these are not the only permits listed in Table 3-1. Marathon's current BAAQMD permits are valid through December 31, 2022, and authorize petroleum-processing facilities at the Refinery. This permit information is part of the public record. Marathon has submitted an additional memorandum, dated April 14, 2022, further supporting the permit maintenance to date related to petroleum refining. This additional information supports the analysis and conclusions of the environmental impact report, and is not significant new information.

Master Response 1, pages 3-1 to 3-10, explains in detail that the DEIR baseline methodology is consistent with CEQA Guidelines Section 15125(a), Environmental Setting, and direction on the environmental baseline. Master Response page 3-2, states:

"Draft EIR Chapter 3, under Assessment Methodology – CEQA Requires a Baseline for Impact Analysis, pp. 3-1 to 3-7, presents further detail on the Project baseline, including a review of baseline requirements, review of historical operational data, and rationale for selection of the Project baseline for the EIR analysis."

The Master Response, page 3-3, continues:

"Draft EIR Chapter 3, under Project Operational Data Informing Selection of Baseline, presents historic petroleum processing throughput at the Refinery over a 5-year period, and annual vehicle and vessel traffic over a 5-year period. Draft EIR p. 3-6 then states, 'The two primary factors for baseline selection were representativeness and conservativeness. Based on the 5-year turnaround, reduced pandemic production, and interest in a conservative baseline, the County has selected the 5-year average as the baseline.'"

The DEIR, as cited in the Master Response, details that the 5-year average from October 1, 2015 to September 30, 2020 as a CEQA baseline captures the period from April 2020 to September 2020. The current non-operation of petroleum processing at the Refinery is incorporated as part of the overall 5-year average baseline case. The FEIR appropriately documents the selection of the 5-year average as the baseline, using detailed information on operations at the Refinery.

That approach is consistent with CEQA Guidelines Section 15125, and relevant case law cited in the Master Response. Non-operation of the Refinery would therefore not be the appropriate baseline for the environmental setting for the Project analysis.

(c) Operational upsets

The Appeal states the HEFA biofuel processing can lead to increased process upsets, including corrosion of equipment as potential contributors to process upsets and that flare operations at the Refinery would have pollution risks that should be disclosed and mitigated. This appeal point is without merit because the FEIR fully reviewed the process hazards related the project, based on the proposed hydrotreating process.

FEIR Chapter 3, Section 3.1.5, Master Response 5: Public Safety, pages 3-37 to 3-43 presents a complete response to process safety and flaring operations raised in comments on the Draft EIR and in the Appeal. In summary, renewable fuel processing with the Project would result in similar or reduced process hazards compared to petroleum operations, and flaring conditions would be reduced.

Master Response page 3-38, discussed process upsets with the Project:

"All hydrogen processing units, regardless of feedstock, must be evaluated for process safety risks. A principal purpose of process safety is to reduce the magnitude of incidents, thereby reducing the harm to people and environment. All refinery design changes undergo review by cross disciplinary teams to ensure the proposed design meets the process safety management (PSM) requirements and acceptable level of risk. As part of the engineering and planning process, Marathon has conducted facility siting analyses, process hazard analyses (PHAs), damage mechanism reviews, and management of changes. The facility siting analysis and PHA are described below."

Discussing the siting analysis, Master Response page 3-38, continues:

"In petroleum refining, there are many worst-case releases, including failure of butane storage, alkylation unit, cat cracker, sulfur plant, ammonia plant, or hydrogen. With HEFA technology, there are only two such scenarios: hydrogen and propane release. The worst-case scenario for a hydrogen release is based on the maximum amount of hydrogen produced, which would be the same both pre- and post-Project conditions. Because the controlling scenarios would exist both pre- and post-Project, there would be no increased process safety risk from renewable feedstock refining. There would be an overall decrease in worst-case releases because most of the potential toxic releases noted above would be eliminated with the transition from petroleum to renewable feedstock refining.

"The causal events for upset conditions in hydrotreating would be the same for HEFA and petroleum. Those events include loss of cooling, loss of power, loss of feed, and loss of hydrogen. Since there is no change to the feed supply, cooling source, feed pumps, and hydrogen plants between hydrotreating petroleum and hydrotreating HEFA, the risk of a causal event that would result in a process upset would be the same for HEFA and petroleum. Therefore, the transition from petroleum processing to HEFA would not result in more or additional process upsets."

Master Response pages 3-42 to 3-43 documents that renewable fuel processing temperatures would be lower than petroleum processing temperatures, and thus would lower the process safety risk:

"Process safety risk reduction measures are evidenced in the number of finite elements that are required for temperature and pressure control during the refining process. The more elements a process has, the higher the probability of a failure. Hydrotreating depends on temperature and pressure control. Temperature is controlled by flow, furnaces, and heat exchangers. In the repurposed 3HDS unit there were 17 shell and tube exchangers; in the new 3HDO unit there would be 10 shell and tube exchangers. As a Refinery, the site has maintained 1,276 shell and tube heat exchangers controlling temperature and reactions as high as 900+°F. In summary, the new process would have less equipment to monitor and maintain than a traditional HDS unit.

“Although more heat is produced when a hydrogen molecule reacts with an oxygen molecule during HEFA processing than when hydrogen reacts with sulfur during petroleum processing, in HEFA the reaction occurs at a much lower operating temperature. Most chemical reactions require heat to promote the reaction. Due to the amount of aromatics in the petroleum feed that need to be hydrotreated to meet the CARB Diesel specification, the reactor operated at approximately 650° F. In the proposed processing, the HEFA reactor temperature would be approximately 535°F. Since a lower temperature is needed and the reaction is more exothermic, less heat is added from external sources. For example, during petroleum processing in the 3HDS unit, two gas fired furnaces ran with all seven burners lit. In the HEFA 3HDO reaction, only one gas fired furnace would run with only four burners lit. Overall, the heat balance is the same whether the heat comes from the reaction or an external source like a furnace. This leads to not only a process safety risk reduction but also an environmental improvement.”

Regarding potential process risks from equipment corrosion, Draft EIR Chapter 3.9, Hazards and Hazardous Materials, 3.9.1 Environmental Setting, 3.9.1.1 Regulatory and Policy Context, pages 3,9-1 to 3,9- 8 presents federal, state, regional, and local safety requirements with which Project refinery and pipeline operations would comply.

Section 3.9.3, Impacts and Mitigation Measures, pages 3.9-17 and 3.9-18 identifies Impact HAZ-2: Create a hazard to workers, the public, and/or the environment through exposure to existing hazardous materials at the site, as a less than significant impact.

The impact discussion notes that “(h)owever, the total amount of crude oil processed would be decreased; thereby decreasing the amount of hazardous materials used in the processing as well a reduction in air toxics such as hydrogen sulfide and benzene handled at the facility. In addition, lower quantities of crude oil would be stored on the Site, and the shutdown of petroleum refining units would result in the operation of fewer units, boilers, vessels, towers, columns, fugitive emissions and other similar equipment, generally reducing the overall hazards associated with the Project.”

The impact analysis cites Cal/OSHA regulations that apply to the use, handling, storage and disposal of hazardous materials, requiring “business emergency response plans to assist local administering agencies in the emergency release or threatened release of a hazardous material. The facility’s plan would be updated to reflect the changes in operations associated with the proposed Project."

The analysis notes that “(up)date of the facility’s current Safety Plan (Injury and Illness Prevention Program [Marathon 2020]) to reflect changed conditions and continued implementation of the Plan would assist in reducing hazards of explosive or otherwise hazardous materials. Continued compliance with these and other federal, state and local regulations and proper operation and maintenance of equipment would minimize the potential impacts of hazardous materials, and therefore, potential for exposure to existing hazardous materials would be less than significant."

Regarding flaring, as described in Master Response 5, Public Safety, the use of flares is often planned during maintenance activities, including startup and shutdown, as scheduled maintenance activities can result in higher-than-normal flow of material to the flare. During equipment maintenance, the equipment and associated piping must be cleared of hydrocarbon before opening, based on both safety and environmental considerations, including compliance with BAAQMD Regulation 8 Rule 10 (Process Vessel Depressurization). Typical procedures include multiple steps of depressurization and purging with nitrogen or steam to the flare header. Other planned uses include startup of hydrogen plants, as off-spec hydrogen with excessive carbon monoxide can poison catalyst, induce hydrogen imbalances, fuel gas imbalances, Gas Plant shutdowns, and flare gas recovery compressor shutdowns. Unplanned uses of flares include compressor trips due to vibration from earthquakes, power outages, instrument malfunctions, and unit upsets. There would be no change to the planned and unplanned use of flares with implementation of the Project, and the pre- and post-project flare emissions are detailed in the FEIR.

Therefore, compared to petroleum refining operations, the Project would have similar or reduced risks from corrosion hazards or other equipment failures.

Master Response page 3-39, regarding flare operations with the Project states:

"The method for flare use would not change between pre- and post-Project conditions; however, the Project would reduce the number of flare units from nine to six and therefore fewer flaring events would be expected. The Refinery uses nine open stack gas flares for petroleum processing and has two flare gas recovery compressors, of which normally one is in operation; the second compressor is started up during turnaround to capture and recover more gases. With implementation of the Project, the number of gas flares would be reduced to six. There would be no change to the flare gas recovery compressors number or use."

FEIR Table 3-2. Pre- and Post-Project Refinery Flare Emissions (Tons per Year), Master Response pages 3-39 to 3-43, presents flare emissions estimates for 40 potential pollutants; in each case, post-Project emissions would be reduced compared to pre-Project conditions.

With regard to flare operations monitoring or mitigation, Master Response page 3-42 notes that "[t]he Refinery's permitting flare limits and monitoring requirements are specified by regulatory limits and BAAQMD permits," and lists three specific permit and three specific reporting requirements that would continue to apply with Project operations.

The DEIR Introduction, Section 1.5, Use of this EIR by Responsible Agencies, page 1-3, notes that BAAQMD is a responsible agency that would consider the EIR in reviewing and approving permits for the Project. BAAQMD permits could include an updated flaring plan:

"In addition to land use permit approval by the County, the Project requires permits from other federal, state and local agencies including the United States Army Corps of Engineers, Bay Area Air Quality Management District, San Francisco Bay Conservation and Development Commission, San Francisco Bay Regional Water Quality Control Board and California State Lands Commission. California state and regional agencies are considered to be responsible agencies under CEQA and must comply with CEQA by considering the environmental impact report prepared by the lead agency. However, responsible agencies must each reach their own conclusions on whether or how to approve their respective permits for the Project (CEQA Guidelines Section 15096)."

Therefore, Project process hazards and flaring operations impacts would be similar to, or reduced, compared to petroleum processing operations.

(d) Food system oil consumption

The Appeal includes statements essentially repeating comments submitted on the DEIR regarding potential land use impacts from soybean oil and corn oil consumption for renewable fuel feedstocks; criticism of the reliance on the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS) review of indirect land use impacts; and requests that Marathon specify the source of renewable fuel feedstocks for the Project. This appeal point is without merit because the food-system related issues were fully addressed in the FEIR at a level of detail that was consistent with CEQA Guidelines Sections 15064(d) and 15358(a)(2).

The Appeal, in discussing potential deforestation effects related to increased renewable fuels production, cites a document, "Animal, vegetable or mineral (oil)? Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States," published in January 2022. The document was not submitted during the DEIR public comment period and is therefore not addressed in the response to comments in the FEIR. Staff has since reviewed the document and finds that its contents do not alter the conclusions found in Master Response 4 of the FEIR.

FEIR Chapter 3, Section 3.1.4, Master Response 4: Land Use & Feedstocks, pages 3-21 to 3-37, addresses DEIR comments on the LCFS program, indirect land use impacts, and feedstock source and mixes.

Master Response pages 3-21 to 3-26 reviews the applicability of the LCFS program to evaluating impacts from the Project. The DEIR and the Master Response acknowledge that the LCFS program is a state-wide, long-term effort, and concludes on Master Response page 3-26 that "[t]herefore, the Project's production of biofuels would be consistent with the State's Low Carbon-Intensity Liquid Fuels goals.

Master Response page 3-27 introduces a detailed discussion of indirect land use issues:

"Regarding the potential for indirect land use changes associated with the Project's feedstock supply, including deforestation, the Draft EIR appropriately assesses the land use impacts associated with the Project's use of crop-based feedstock.

"CEQA requires that indirect physical changes resulting from a project be addressed only to the extent they are 'reasonably foreseeable,' pursuant to CEQA Guidelines Sections 15064(d) and 15358(a)(2), and those indirect impacts can be addressed in more general terms than direct impacts 'where it would be difficult to predict them with any accuracy.' Further, CEQA does not require evaluation of speculative impacts, pursuant to CEQA Guidelines Sections15064(d)(3) and 15145. While potential upstream land use changes are difficult to predict with accuracy, the Draft EIR does address indirect land use effects related to biofuel feedstocks."

Master Response pages 3-27 to 3-31 then details the LCFS program's disincentives to use of feedstocks with high carbon intensity; page 3-29 cites the DEIR conclusions:

"The Draft EIR, Chapter 3.8, p. 3.8-15, also explains how the credit and deficit system at the heart of the LCFS framework operates as a disincentive to the production of fuels from feedstocks that result in upstream land use changes:

'[B]iofuels produced from feedstock with a high land use change score will be disadvantaged; that is, they would produce greater deficits or fewer credits, relative to those produced from a feedstock that causes less land use change. This creates an economic incentive for producers to utilize the lowest CI feedstock available, as the product's value is inextricably linked to the number of credits it can produce.'"

Master Response pages 3-30 to 3-31 discusses the uncertainty on the links between biofuel development and deforestation and the complications quantifying them:

"The difficulty in accurately predicting the upstream land use impacts of crop-based biofuels is further exacerbated when, as is the case here, a mix of feedstocks is used. Commenters themselves acknowledge this uncertainty, noting that 'the environmental and climate impacts" of different biofuel feedstocks "may vary.' (Comment O12-41). Among this feedstock mix, Commenters pay special attention to the Project's anticipated use of soybean oil ("SBO"). Specifically, Commenters argue that the Project's potential to create a demand shock for SBO will lead to increased demand for other crops worldwide, including palm oil, and will ultimately result in deforestation in the Brazilian Amazon and Indonesia (see for example comments O12-62, O12-63, and I1-8).

"There are reasons to doubt this conclusion, which itself depends on complex variables, such as the relative price-elasticities of crop-based cooking oils and consumers' willingness to substitute them. As a threshold matter, Marathon has said it would not use palm oil as part of the Project, and the comment's market-based argument is necessarily indirect by nature."

Master Response pages 3-31 to 3-32 further addresses feedstock sources:

"The comments raise the concern that the Project would rely on non-waste food system oils and the Draft EIR did not describe the specific blend of feedstocks. The comments argue that the EIR must 'specify the exact amount of each feedstock that will be used in the Project year to year' or otherwise the County must evaluate a reasonable array of feedstock scenarios, including a 'reasonable worst-case scenario' for feedstock consumption and its impacts.

"Draft EIR Chapter 2, Project Description, p. 2-36, notes that the Project is 'expected to include' three identified feedstocks: (1) distillers corn oil (DCO), soybean oil (SBO), and tallow or previously rendered fats. Processing facilities for these feedstocks 'are usually in the region of the initial agricultural suppliers, such as the Midwest' and 'as technology evolves, other biological fuel sources such as used cooking oils, and plant and animal processing by-products, may also be used as feedstock using substantially the same equipment and processes as those proposed under the proposed Project.

"The Draft EIR specified presently contemplated project feedstock, and CEQA does not require speculation about future fuel sources that might materialize. CEQA Guidelines Sections 15124(c) and (d) require a general description—avoiding 'extensive detail'—of the project's technical, economic, and engineering characteristics."

(e) Odor mitigation plan

The Appellants contend that by allowing an Odor Management Plan to be developed during the construction phase of the Project, the County improperly deferred mitigation for odor impacts. This appeal point is without merit because the FEIR provides adequate detail of the Odor Management Plan and the plan would not be deferred, it would be implemented as a mitigation with the project prior to operations.

Mitigation Measure AQ-2 requires the Applicant to prepare and implement an Odor Management Plan to address odor issues facility-wide prior to operations. CEQA allows an agency to defer the specific details of a mitigation measure when it is impractical or infeasible to include these details during the project's environmental review provided that the agency (i) commits itself to the mitigation, (ii) adopts specific performance standards that the mitigation will achieve, and (iii) identifies the type(s) of potential action(s) that can feasibly achieve those performance standards [CEQA Guidelines Section 15126.4(a)(1)(B)]. Mitigation Measure AQ-2 meets those criteria: the measure requires the County to confirm that the Applicant has prepared and implemented an Odor Management Plan prior to operations; adopts specific, objective, and measurable performance standards, in this case regarding the number of odor complaints; and directs the Applicant to identify equipment and procedures to use to address odor issues, including operating procedures to inspect and evaluate the effectiveness of odor control equipment and operation of the wastewater treatment plant, and specifies remedial actions in the event that the performance criteria are not met.

Proper deferment requires the agency to ensure that the mitigation will be in place prior to implementation of the project component that triggers the need for mitigation. In this case, the potential for objectionable offsite odors arises from project operations and not construction. Because the Odor Control Plan would be implemented prior to project operations, its timing is not improperly deferred.

Furthermore, the FEIR details many of the specific technologies that would be implemented with the project. Impact AQ-5 analysis states, "Odor management controls including, but not limited to, carbon sorption, incineration, biofilter use, and chemical scrubbing, all in conjunction with a vapor recovery system and nitrogen blanketing of storage tanks are being evaluated to determine the most effective and practicable method to reduce odors from the storage tanks and loading and unloading activities. These options are the most utilized odor control methods for biofuel production. The chosen method will be reviewed with the BAAQMD and County prior to implementation." This detailed list of implemented technologies provides thorough information about the details of the OMP. These mitigations are further strengthened by the requirement that the chosen method be reviewed with the BAAQMD and County prior to implementation of the project.

(f) Cumulative impacts

The Appeal states that the FEIR does not adequately account for cumulative impacts of the Project and the nearby Phillips 66 Rodeo Renewed project, with respect to food crop markets and related land use impacts. This appeal point is without merit because the FEIR adequately addressed cumulative impacts associated with the project pursuant to CEQA guidelines.

The Appeal, in discussing potential deforestation effects related to increased renewable fuels production, cites a document, "Animal, vegetable or mineral (oil)? Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States," published in January 2022. The document was not submitted during the DEIR public comment period and is therefore not addressed in the response to comments in the FEIR. Staff has since reviewed the document and finds that its contents do not alter the conclusions found in Master Responses 3 and 4 of the FEIR, which address concerns related to cumulative impacts and feedstock-based-demand land use changes.

FEIR Chapter 3, Section 3.1.3, Master Response 3: CEQA Cumulative Impacts, pages 3-17 to 3-21 addresses the DEIR analysis of cumulative impacts of the Project and the Phillips 66 Rodeo Renewed project (“Phillips 66 project”). Master Response page 3-18 notes that the analysis of cumulative impacts to air quality, biological resources, energy, and greenhouse gases (GHG) specifically included the Phillips 66 project.

Regarding cumulative indirect land use impacts, Master Response 3 references Master Response 4: Land Use & Feedstocks, which states:

“Some comments assert that the Draft EIR’s discussion of cumulative impacts from the Project and other similar projects is inadequate.

“The Draft EIR, Chapter 4, Cumulative Impacts, Section 4.2, Related Projects Considered in the Cumulative Impact Analysis, identifies related projects, including other refiners of renewable fuels. Section 4.3, Cumulative Impacts to Environmental Resources, pp. 4-7 to 4-16, explicitly addresses the potential for cumulative direct environmental impacts from those similar projects. While such direct impacts can be understood and assessed with greater clarity, the comments characterize land use emissions associated with these feedstocks as ‘difficult-to-predict’ (see for example O12-88). For cumulative indirect impacts as suggested in the comments, there are again limits to how accurately they can be predicted in the Draft EIR. As such, the Draft EIR discusses those upstream impacts at an appropriate level of generality. Since this generality is appropriate for the Project alone, it is likewise appropriate when considering the cumulative upstream impacts from the Project and other similar projects, each with their own blend of feedstock types and sources. In sum, the Draft EIR identification of an extensive list of similar projects, together with an appropriate discussion of upstream land use changes, is adequate under CEQA.

“In addition, CEQA case law makes clear that the Draft EIR’s discussion of these cumulative impacts is sufficient. The discussion of cumulative impacts need not provide as great detail as is provided for the effects attributable to the project alone and should be guided by the standards of practicality and reasonableness.”

As discussed above, the Appeal references a January 2022 study, in addition to others cited in comments on the DEIR, that addresses potential deforestation effects resulting from increased renewable fuel production on a world-wide basis. The Master Response 4 conclusions noted above, regarding the appropriate level analysis of such cumulative impacts, would continue to apply.

(g) California climate pathways

The Appeal states that the County did not consider the Appellants' DEIR comments related to how the Project would produce an oversupply of renewable diesel that exceeds the supply anticipated in analysis of California's climate pathways and that the Project would therefore be inconsistent with California's climate pathways. This appeal point is without merit because the FEIR provided a detailed analysis of the project's consistency with Senate Bill 32 and the 2017 Climate Change Scoping Plan Update.

The appeal references pages 44 through 58 and 72 through 75 of the Appellants' comment response to the DEIR. These sections of the comment letter are related to the adequacy to disclose and address project greenhouse gas and climate impacts related to biofuel oversupply (p. 44-58) and the cumulative impacts analysis consideration of biofuel production on the State's Climate Goals (p. 72-75). Each individual comment within these pages was identified and responded to as detailed in FEIR Chapter 3, Response to Comments. These comments are responded to in Master Response 3, Cumulative Impacts, Master Response 4, Land Use & Feedstocks, Response O12-90 Response O12-94, and Response O12-95.

The climate pathways analysis referred to is a series of technical studies prepared by Energy and Environmental Economics, Inc. to help inform considerations for the initial development of the Assembly Bill 32 2022 Scoping Plan Update by the California Air Resources Board. When complete, the 2022 Scoping Plan Update will assess progress towards achieving the Senate Bill (SB) 32 2030 target of statewide greenhouse gas emissions reduced to 40% below the 1990 level by 2030, and lay out a path for the State of California to achieve carbon neutrality no later than 2045. The 2022 Scoping Plan Update and associated pathways, however, are still in workshop phase; they are under development and have not gone through the Rulemaking process and have not been adopted; they are therefore not applicable to the proposed Project, thus, the project is not inconsistent with them. Furthermore, the analysis referenced in the Appeal summarizing California climate pathways body of research was acknowledged for the record and provided as part of the FEIR to the decision-making bodies for their consideration in reviewing the Project.

The Project was analyzed for consistency with SB 32 and the 2017 Climate Change Scoping Plan Update, which is in place and therefore applicable to the proposed Project at the time the DEIR was published. The 2017 Scoping Plan was described in the DEIR on pages 3.8-11 and 3.8-12 of Section 3.8.2, Greenhouse Gas Emissions. Consistency with the applicable plans, policies, or regulations adopted for the purpose of reducing GHG emissions was analyzed in Impact GHG-2 on DEIR page 3.8-22 and found to be less than significant.

As stated in the previous section, the FEIR addresses the cumulative impacts at an appropriate level of analyses, as explained in Master Response 3 and Master Response 4. The analysis is also adequate when considering consistency with SB 32.

"The Draft EIR, Chapter 4, Cumulative Impacts, Section 4.2, Related Projects Considered in the Cumulative Impact Analysis, identifies related projects, including other refiners of renewable fuels. Section 4.3, Cumulative Impacts to Environmental Resources, pp. 4-7 to 4-16, explicitly addresses the potential for cumulative direct environmental impacts from those similar projects. While such direct impacts can be understood and assessed with greater clarity, the comments characterize land use emissions associated with these feedstocks as 'difficult-to-predict' (see for example O12-88). For cumulative indirect impacts as suggested in the comments, there are again limits to how accurately they can be predicted in the Draft EIR. As such, the Draft EIR discusses those upstream impacts at an appropriate level of generality. Since this generality is appropriate for the Project alone, it is likewise appropriate when considering the cumulative upstream impacts from the Project and other similar projects, each with their own blend of feedstock types and sources. In sum, the Draft EIR identification of an extensive list of similar projects, together with an appropriate discussion of upstream land use changes, is adequate under CEQA.

"In addition, CEQA case law makes clear that the Draft EIR's discussion of these cumulative impacts is sufficient. The discussion of cumulative impacts need not provide as great detail as is provided for the effects attributable to the project alone and should be guided by the standards of practicality and reasonableness."

The cumulative impact analysis is sufficient as required by CEQA, thus, evaluating the consistency of all renewable fuels projects is not necessary to determine the project's consistency with SB 32 and California's Climate Change Scoping Plan.

(h) Transportation risk impacts

The Appeal states that the FEIR does not adequately analyze the potential effects of spills of non-petroleum oils on the marine environment, what the cleanup of such spills would entail, and the Project's responsibilities for cleanup of potential spills. This appeal point is without merit because fully analyzed these impacts and appropriate mitigation.

DEIR Chapter 3.4, Biological Resources, Chapter 3.9, Hazards and Hazardous Materials, and Chapter 3.10, Hydrology and Water Resources analyzed potential impacts of spills, and document that impacts of spills of vegetable oil or animal fat feedstocks would differ from that of petroleum oil spills. However, such Project impacts would still be a significant and unavoidable effect. DEIR Chapter 3.4, page 3.4-4 as revised by the FEIR, page 4-8 states:

"Renewable feedstocks – vegetable oils and animal fats – would be transported via barge to the Refinery terminals. Vegetable oils and animal fats share common physical properties with petroleum oils and produce similar environmental effects when spilled (EPA 2020). Like crude oil, vegetable oils and animal fats may sink and form tar balls or coat the benthic floor. These oils tend not to evaporate, but instead leave a thick, viscous residue on the surface of receiving waters. Vegetable oils and animal fats can:

- Coat animals and plants with oil and suffocate them;
- Be toxic and form toxic products;
- Destroy and degrade habitat by fouling shorelines, the water column and the benthic substrate;
- Produce rancid odors; and
- Linger in the environment for many years."

"Research and previous spills have shown that release of animal fats and vegetable oils into water or overland kills or injure[s] wildlife. Wildlife, including waterbirds and fish, that become coated with animal fats or vegetable oils are unable to keep themselves warm, may suffer from dehydration, diarrhea, or starvation. Aquatic life can suffocate because of depletion of oxygen caused by spilled animal fats and vegetable oils in water.

“Marathon would be required to update the Refinery’s FRP [Facility Response Plan] and Spill Prevention, Control, and Countermeasure Plan (SPCC) to demonstrate preparedness to respond to vegetable oil and animal fat spills. However, there are limitations to thorough containment and cleanup of a major oil spill. As was determined in the Avon and Amorco EIRs, even with specific procedures to protect sensitive biological resources in the Project vicinity, adverse impacts to special status species, protected habitats, and migratory corridors and nursery sites for native species as a result of a major spill would remain significant and unavoidable.”

The DEIR acknowledges that the Project would eliminate the transport of materials like ammonia or sulfuric acid to the Refinery, while renewable feedstocks would be delivered to the Refinery. DEIR Chapter 3.9, page 3.9-16 states:

“The principal change associated with the proposed Project is that crude oil, the major portion of which is delivered to the Martinez Facility via marine vessel, would no longer be used as a feedstock. Instead, renewable feedstocks would be delivered to the Martinez Facility via marine vessel and rail. As a result of the Project, some commodities such as ammonia and sulfuric acid would no longer be transported, while commodities such as renewable feedstock, which includes vegetable oils (e.g., soybean oil and corn oil), rendered fats and other miscellaneous renewable feedstocks, would increase via rail transport.”

The FEIR includes several comments and responses on marine transportation risks and potential impacts of feedstock spills and mitigation.

The San Francisco Bay Conservation and Development Commission (letter A5) raised several points regarding marine risks. FEIR Response A5-9, pages 3-61 to 3-62 notes that:

“Potential environmental impacts and hazards to habitat areas caused by renewable fuels and feedstocks are discussed in the Draft EIR in Section 3.4, Biological Resources, on pp 3.4-40 to 3.4-41 and Section 3.9, Hazards and Hazardous Materials, on page 3.9-15. Additional details regarding environmental impacts and hazards from renewable feedstocks and renewable fuels are provided in Master Response 4: Public Safety and in responses to California State Lands Commission comments, particularly Response A6-31.

“Consistency with the San Francisco Bay Plan is analyzed in Draft EIR Section 3.4 Biological Resources on page 3.4-33. Safety plans, training, and incident planning required for Refinery operations and transfer of hazardous materials over water are discussed in Draft EIR Section 3.9, Hazards and Hazardous Materials.”

The DEIR and FEIR acknowledge that spill hazards and release of contaminants would be a potentially significant impact. FEIR Response A5-10, page 3-62 states:

“Response A5-10: Operational impact HWQ-1 discusses the protocols in place to minimize the potential for accidental releases. However, as stated in the Draft EIR, adherence to these protocols and spill response measures will not guarantee that contaminants will never be released. The probability of a serious spill would be minimized to the extent feasible with implementation of the SLC lease conditions, but the risk cannot be eliminated. Because a large spill could still occur and result in impacts on water quality that would be significant and unavoidable, this impact is listed as 'potentially significant.'"

The California State Lands Commission (letter A6) also presented comments on marine spills and agency or private-party responsibilities, in relation to the operation of the marine oil terminals (MOTs) that would serve the Project. FEIR Response A6-5, pages 3-63 to 3-65, presents the existing agency oversight and mitigation requirements for the Amorco and Avon MOTs. In particular, Response A6-5 cited Mitigation Measure HAZ-1 on DEIR pages 3.9-16 to 3.9-17 in Section 3.9, Hazards and Hazardous Materials, provides that oversight of transport of non-petroleum oils would be ensured, with the following clarification:

"If terminal operations do not allow for regular compliance and inspection of LKS [Lempert-Keene-Seastrand Oil Spill Prevention and Response Act] and MOTEMS [Marine Oil Terminal Engineering and Maintenance Standards] requirements by the CSLC [California State Lands Commission] and/or OSPR [Office of Spill Prevention and Response], Marathon shall employ a CSLC-approved qualified third-party to provide oversight as needed to ensure the same level of compliance as for a petroleum-handling MOT facility, and to ensure maximum protection of the environment from potential spills and resulting impacts."

Thus, the FEIR appropriately evaluates the marine transportation risks associated with renewable fuel feedstocks.

II. Appellants contend: "The FEIR Fails to Comply with the CEQA Requirement to Respond to Public Comments"

The Appeal states that the FEIR does not respond to a range of comments and technical studies submitted as part of public comments on the DEIR. Therefore, the Appeal asserts, the FEIR does not meet CEQA Guidelines Section 15008, that requires responses based on reasoned analysis, with detail corresponding to the level of detail in the comments.

The Appeal notes general points about the organization of the FEIR, Master Responses, and other responses, and how individual responses reference the Master Responses. The Appeal then presents three specific topics as inadequately addressed in FEIR: the problem of runaway reactions and corrosion of equipment as potential contributors to process upsets; the completeness of the cumulative analysis; and renewable fuel oversupply as it concerns California's climate goals. Those three topics are addressed in detail in the FEIR as described herein:

- Response I(c) above addresses Appeal comments on process hazards.
- Response I(e) above addresses Appeal comments on cumulative impacts.
- Response I(g) above addresses renewable fuel oversupply issues as it concerns California's climate paths.

III. Appellants contend: "The County Has Made No Findings Concerning Choice of Alternatives and Throughput Volumes"

Findings for Alternatives

The Appeal notes that the FEIR reviews the green hydrogen alternative and the reduced feedstock alternative; the latter is identified as the "environmentally superior" alternative but the Appeal states that the FEIR does not identify the "preferred alternative" and that identification of the "preferred alternative" should be supported by findings based on evidence in the record.

DEIR Chapter 5, Alternatives, pursuant to CEQA Guidelines 15126.6, Consideration and Discussion of Alternatives to the Proposed Project, analyzed the No Project Alternative, the Reduced Renewable Feedstock Throughput Alternative, and the Green Hydrogen Alternative. The chapter reviews impacts of each alternative for each environmental topic, noting the level of significance of the impact compared to the impacts of the Project. Section 5.4, Environmentally Superior Alternative, pages 5-11 to 5-13, cites CEQA Guidelines Section 15126.6(e)(2):

"The 'no project' analysis shall discuss the existing conditions at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, 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. If the environmentally superior alternative is the 'No Project' Alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives."

Section 5.4, Table 5-1, Comparison of Proposed Project with Project Alternatives summarizes the alternatives analysis. The Project would have unavoidable significant environmental impacts, even considering implementation of feasible mitigation measures, related to air quality, biological resources, hazards and hazardous materials, and hydrology. Table 5-1 shows that the Reduced Throughput Alternative would have the same significant unavoidable impacts for the four topics above, although the degree of effect would be reduced for air quality and energy. Section 5.4 page 5-13 concludes, pursuant to CEQA Guidelines15126.6(e)(2):

"Because it would not result in any impacts that would be greater than the proposed Project, and in many cases would result in reduced impacts compared to the proposed Project, the Reduced Renewable Feedstock Throughput Alternative is the environmentally superior alternative. The Reduced Renewable Feedstock Throughput Alternative, however, would generate fewer jobs and result in a lower volume of renewable fuels being brought to the market to support the State's low-carbon fuel goals, and would not achieve Project objectives as well as the proposed Project."

CEQA Guidelines do not require identification of, or findings for, a "preferred alternative." The FEIR reviews alternatives to the Project and identifies for the record the conclusions for the Environmentally Superior Alternative.

Nevertheless, staff has prepared additional findings to supplement the findings made by the County Planning Commission under Public Resources Code section 21081(a) and CEQA Guidelines section 15091(a), including specific findings related to the alternatives analyzed in the environmental impact report. The additional findings are included in the attached CEQA Findings.

Project Throughput Limits

The Appeal states that the FEIR does not discuss conditions of Project approval that would limit Refinery throughput to 48,000 barrels per day (bpd) of feedstock. The Appeal states that FEIR analyzed the impact of 48,000 bpd, "yet nothing constrains the Project from processing more feedstock than that, with attendant greater impacts." The Appeal requests that the County make throughput volume a condition of approval.

As analyzed in the FEIR, the Project would propose to process up to 48,000 barrels per day (bpd) of renewable feedstock. DEIR Chapter 2, Project Description, under Section 2.1 Refinery History and Proposed Project Summary, page 2-1 states:

"Marathon anticipates that operations under the proposed Project would begin in 2022 with an estimated production of 23,000 bpd, ramping up to full production of 48,000 bpd expected to be achieved by the end of 2023. The repurposed Refinery would operate 24 hours per day, seven days per week."

Section 2.5.4.1 Project Modifications at Refinery, page 2-16 then states:

"Conversion of the Refinery to a facility for processing of renewable feedstocks would require installation of new equipment and modification of some existing units currently used for processing of crude oil. Other units that cannot be converted for production of renewable fuels would be taken out of operation and demolished. Once all equipment modifications have been completed, and due to limitations in the production of the on-site hydrogen plant, the Refinery would have capacity to receive and process up to 48,000 bpd of fresh renewable feedstock."

The 48,000-bpd throughput limit is both a physical limit based on the configuration of the facility and a legal limit based on permitting constraints that will be implemented by BAAQMD. The 48,000-bpd throughput would be limited, as noted above, by on-site operating conditions. Further, the EIR discusses that Project throughput would be subject to Bay Area Air Quality Management District (BAAQMD) regulations and permitting. DEIR Introduction, 1.5.1, Use of this EIR by Responsible Agencies, cited above under the topic "Failure to account for potentially increased operational upsets," notes that the Project requires permits from other federal, state, and local agencies including among others, the BAAQMD.

DEIR Chapter 3.3, Air Quality, explains that the Project would require an Authority to Construct (ATC) from the BAAQMD. That ATC permit would be based on the proposed 48,000 bpd throughput. Chapter 3.3, page 3.3-1, notes that the Project Applicant's Authority to Construct permit application has been submitted to the BAAQMD. Page 3.3-1 continues:

"The Marathon Martinez Refinery (the Refinery) is currently permitted to process approximately 161,000 barrels per day (bpd) of crude oil. After completion of the project, the facility's capacity would be approximately 48,000 bpd of renewable feedstocks."

Therefore, Project throughput, with an approved BAAQMD ATC, would be limited to 48,000 bpd. Any proposed increase in that throughput would require BAAQMD review and approval, including, as appropriate, CEQA review. Further CEQA review, therefore, would be required for modifications to the 48,000 bpd limit in the ATC permit. If Marathon were to desire to increase throughput limits, that change to the project would require a modified BAAQMD permit. If there is a substantial change to the project because of a proposed increase in the throughput limit, the substantial change would trigger subsequent environmental review under CEQA (CEQA Guidelines, § 15162).

IV. Appellants contend: "New Information Describing the Project Provided in the Response must be Recirculated to Allow for Public Comment"

The Appeal states that the identification of HEFA as the refining technology in Master Response 5 of the FEIR constitutes new information that requires recirculation of the DEIR.

Section 15088.5(a) of the CEQA Guidelines states "New information added to an EIR is not 'significant' unless the EIR is changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project …" Information regarding refinery operations was included in DEIR Section 2.5, Project Operations and Table 2-1: Refinery Equipment Modifications, which includes a description of how refinery equipment would be used during operations. This information provided the basis for the impact analysis in the DEIR. Environmental impacts with potential to occur as a result of the refining process were analyzed in the DEIR in Section 3.3, Air Quality, Section 3.8, Greenhouse Gas Emissions, and Section 3.9, Hazards and Hazardous Materials, and Section 3.10, Hydrology and Water Resources.

Response I(a) above also addresses Appeal comments on HEFA as the technology that would be utilized by the proposed Project during refining of renewable feedstocks. No new or additional potentially significant environmental impacts arise from identifying the refining process as "HEFA" in the FEIR, nor does it change either the type of environmental impacts arising from the project or their severity. Therefore, the identification of "HEFA" as the processing technology in the FEIR is not significant new information that requires recirculation of the EIR for public comment.

V. Appellants contend: "The Statement of Overriding Considerations is Inadequate"

The Appeal contends that the Statement of Overriding Considerations is intended to "replace" required implementation of feasible mitigation measures to address significant impacts identified in the CEQA review, and that significant impacts associated with process safety and land use are neither identified, nor addressed. The Appellants cite case law suggesting that there are "feasible" mitigation measures which could be applied to reduce identified significant impacts below significance levels.

As the lead agency under CEQA for preparation, review, and certification of the FEIR, the County is responsible for determining the potential environmental impacts of the proposed project, which of these impacts would be significant, and which impacts can be mitigated through implementation of feasible mitigation measures to avoid or minimize such impacts to a level of "less than significant".

CEQA requires the lead agency to balance the benefits of a proposed project against its significant and unavoidable adverse impacts when determining whether to approve the project. In particular, Public Resources Code Section 21081(a) provides that no public agency may approve or carry out a project for which an environmental impact report has been certified that identifies one or more significant effects on the environment that would occur if the project is approved or carried out, unless the public agency makes one or more of three findings with respect to each significant effect.

Public Resources Code Section 21081(b) requires that where a public agency finds that specific economic, legal, social, technological, or other considerations, including considerations for the provision of employment opportunities for highly trained workers, make infeasible the mitigation measures or alternatives identified in the EIR and thereby leave significant unavoidable effects, the lead agency must also find that overriding economic, legal, social, technological, or other benefits of the project outweigh the significant effects of the project.

When the lead agency approves a project which would result in the occurrence of significant effects identified in the FEIR, but would not be avoided or substantially lessened, the agency must state in writing the specific reasons to support its action based on the Final EIR and/or other information in the record. The County's CEQA findings and Statement of Overriding Considerations (Statement), attached as Exhibit B, meet that requirement.

The County's Statement discusses the rationale for approving the Project based on the infeasibility of implementing mitigation measures to sufficiently reduce identified impacts and the project's outweighing benefits. As noted in the Statement, the Project benefits, individually and collectively, outweigh potential significant unavoidable adverse impacts.

Key findings in the Statement are summarized below, and, where appropriate, the FEIR topic is noted that provides the information on the record to support the finding:

1. Repurposing of existing refinery: The Project would preserve high quality jobs in the Martinez area, while minimizing construction activities and related land use impacts; the repurposed refinery would involve production of renewable fuels in compliance with the state's Low Carbon Fuel Standard (LCFS).

2. Reduction of hazards associated with refining of crude oil: Replacement of crude oil feedstocks with renewable feeds will significantly reduce the use and handling of hazardous materials; similarly, the reduction in the refinery's operating units as part of the project will further reduce potential hazards associated with the refining processes. (FEIR Chapter 3.9 Hazards and Hazardous Materials)

3. Emissions Reductions: Significant emissions reductions are envisioned as part of the project, including those of criteria pollutants, toxic air contaminants and greenhouse gases (GHG), thereby providing both a local and regional benefit to the residents of Martinez and the Bay Area. These reductions will help to achieve the goals of the Bay Area Air Quality Management District's (BAAQMD) 2017 Clean Air Plan, California Air Resources Board Update to the Climate Change Scoping Plan (CARB 2017), Governor Newsom's Executive Order N-79-20 regarding the desired goal of replacing fossil fuels with renewable fuels, as well as other initiatives promulgated to achieve carbon neutrality no later than 2045. These emissions reductions will apply to both stationary and mobile sources and will have

benefits both locally and throughout California (or wherever renewable fuels are used). (DEIR Chapter 3.3 Air Quality)

4. Energy Use: The project will utilize significantly less energy by decreasing the use of electricity and natural gas in the refining process at the Martinez facility. This will help to meet the state's Renewable Portfolio Standard. (DEIR Chapter 3.6 Energy)

5. Transportation Benefits: Consistent with CEQA Guidelines section 15064.3(b), the proposed project will result in a reduction of vehicle miles traveled (VMT) by both refinery employees and truck trips. (DEIR Chapter 3.14 Transportation)

6. Diversion of Waste Streams: Recycling of organic wastes and associated by-products (e.g., used cooking oils, rendering fats/oils/greases, etc.) will help to reduce demand on landfill space while generating a secondary revenue stream for recycling of these wastes. (DEIR Chapter 3.13, Public Services)

The Appellants assert that certain impacts are inadequately addressed in the Statement of Overriding Considerations. Specifically, Appellants are concerned with safety and land use issues. These issues were evaluated in the DEIR and the FEIR. The FEIR Master Response 4: Land Use & Feedstocks, Master Response 5: Public Safety, and Master Response 2: CEQA Alternatives. As presented above, this response further addresses safety, land use, and alternatives topics. Odor management issues were evaluated in the DEIR, in responses to comments from the BAAQMD in the FEIR Section 3.2.4, and above in this Response. For all those topics, the FEIR and the Response herein continue to conclude that the Project would not have unavoidable significant adverse impacts. None of these topics raised in the Appeal identify a "new" significant impact which has not been evaluated in the DEIR or FEIR. Therefore, impacts related to safety or land use would not require findings of overriding considerations. As noted above, the CEQA findings and the Statement reflect content in the FEIR and are supported by substantial evidence in the public record.

CONCLUSION

The proposed Martinez Refinery Renewable Fuels Project, with the attached Conditions of Approval, is consistent with the General Plan and the Heavy Industrial zoning designation for the site; all environmental impacts would be mitigated to less-than-significant levels or overriding considerations exist; the health, safety, and general welfare of the public would be preserved; and there would be economic benefits as a result of the project. The project's benefits include providing jobs, improving air quality, reducing the amount of hazardous materials in the area, reduction in greenhouse gas emissions, and decrease energy (electricity and natural gas) demand at the facility.

Staff recommends approval of the project.

FINDINGS AND CONDITIONS OF APPROVAL FOR COUNTY FILE #CDLP20-02046, MARATHON PETROLEUM CORPORATION (APPLICANT / OWNER)

I. FINDINGS

A. CEQA Findings

1. Environmental Impact Report

The Martinez Refinery Renewable Fuels Project proposes to modify the existing Marathon Martinez Refinery to repurpose the Refinery for production of fuels from renewable sources rather than from crude oil. Some existing Refinery equipment would be altered or replaced, and additional new equipment units and tanks would be installed, to facilitate production of fuels from renewable feedstock. Crude oil processing equipment that cannot be repurposed for processing of renewable feedstock would be shut down and removed from the Refinery based on an event-based decommissioning plan. As a result of the project, the facility would no longer refine crude oil into petroleum-based products.

The Department of Conservation and Development determined that an environmental impact report (EIR) was required for the project. Accordingly, the County prepared an EIR for the project (State Clearinghouse# 2021020289). The Final EIR includes a Draft EIR, comments on the Draft EIR, and Responses to Comments on the Draft EIR. The Notice of Preparation of the EIR was posted on February 17, 2021, and a public Scoping Meeting was held on March 15, 2021. Both written and oral comments were received during public comment period and the Scoping Meeting; the Scoping Meeting comments were responded to in the Draft EIR, which was released for public review on October 14, 2021, with a Notice of Availability. A 60-day comment period for the Draft EIR began on October 18, 2021, and ended December 17, 2021. During the comment period, the County received 251 comment letters on the Draft EIR for the project. The comment topics included a wide breadth of concerns from local and state agencies as well as organizations and individuals. The major topics include Project Baseline, CEQA Alternatives, CEQA Cumulative Impacts, Land Use & Feedstock Impacts, and Public Safety.

The County's Reponses to Comments received are provided in the Final EIR that has been prepared for the project. The Final EIR also includes County-initiated updates and errata to the Draft EIR. These errata constitute minor text changes to the Draft EIR and occur in Chapter 1 Introduction; Chapter 2 Project Description; Chapter 3 Environmental Impact Analysis, Methodology and Baseline, Section 3.3 Air Quality, Section 3.4 Biological Resources, Section 3.5 Cultural Resources, Section 3.8 Greenhouse Gas Emissions, Section 3.9 Hazards and Hazardous Materials, Section 3.10 Hydrology and Water Resources, Section 3.15 Utilities and Service Systems; and Chapter 4 Cumulative Impacts. All changes are identified in chapter 4 of the Final EIR. The changes were made primarily to correct grammatical and typographical errors, as well as to improve accuracy and readability of certain passages. The text changes are not the result of any new significant adverse environmental impact, and do not alter the effectiveness of any mitigation included in the pertinent section, and do not alter any findings in the Draft EIR.

2. **Findings Regarding Potential Environmental Impacts**

"No Impact" or "Less than Significant Impact"

Contra Costa County is the lead agency under the California Environmental Quality Act (CEQA) for preparation, review, and certification of the EIR for the Martinez Refinery Renewable Fuels Project. As the lead agency, the County is also responsible for determining the potential environmental impacts of the proposed action, which of those impacts are significant, and which impacts can be mitigated through imposition of feasible mitigation measures to avoid or minimize such impacts to a level of "less than significant." The EIR for the project considered the project's impacts, which are summarized in Table ES-1 of the Draft EIR. The project would have either no impacts or less than significant impacts related to Agriculture and Forestry, Mineral Resources, Population and Housing, Recreation, and Wildfire. Potentially significant impacts were also identified, all of which can be mitigated to a less-than-significant level. These impacts affect the environmental topics of:

- Air Quality
- Biological Resources
- Geology and Soils
- Greenhouse Gas Emissions
- Hazards and Hazardous Materials
- Hydrology and Water Quality

Environmental analysis contained in the EIR determined that measures were available to mitigate these potential adverse impacts to less-than-significant levels. The recommended mitigation measures are included within the Mitigation Monitoring and Reporting Plan, which describes the timing and responsible agency for monitoring compliance with all mitigation measures. The mitigation measures have also been incorporated into the recommended conditions of approval.

Significant Unavoidable Environmental Impacts

Pursuant to Public Resources Code Section 21081 and CEQA Guidelines Section 15091, no public agency shall approve and carry out a project where an EIR has been certified, which identifies one or more significant impacts on the environment that would occur if the project is approved, unless the public agency makes one or more findings for each of those significant impacts, accompanied by a brief explanation of the rationale for each finding. The possible findings, which must be supported by substantial evidence in the record, are:

- Changes or alterations have been required in, or incorporated into, the project that mitigate or avoid the significant impact on the environment.

- Changes or alterations are within the responsibility and jurisdiction of another public agency and have been, or can and should be, adopted by that other agency.

- Specific economic, legal, social, technological or other considerations make infeasible the mitigation measures or project alternatives identified in the EIR.

The EIR for the proposed project identified six significant and unavoidable impacts related to air quality, biological resources, hazards, and water quality, including:

Air Quality

Impact AQ-2: NOx emissions from rail traffic in Placer County and marine vessels in the SJVAPCD would exceed significance thresholds, resulting in significant and unavoidable impacts. The County has no authority to impose mitigation measures on rail traffic based on federal preemption, even if any were feasible, on that activity. The NOx emissions from marine vessels (tugs and barges) and rail traffic in the SJVAPCD region are estimated to be 27.06 tpy which would exceed the SJVAPCD CEQA threshold of 10 tpy, with a majority (26.3 tpy) from marine vessels. The overall project will decrease NOx emissions by over 500 tpy. The majority of the emission reductions would take place in the BAAQMD. However, as documented in the EIR, it is well known that Bay Area emissions are transported to the San Joaquin Valley and contribute to air quality standard violations in that region. Therefore, a substantial reduction in NOx emissions in the Bay Area would have a positive effect on air quality in the San Joaquin Valley. Additional mitigations are not warranted given the overall reductions in NOx emissions and explanation of likely reduced NOx in San Joaquin Valley from reductions in NOx in the BAAQMD jurisdiction.

Thus, the project has incorporated components which avoid or substantially lessen the significant environmental effect.

Impact AQ-4: Though the Project would result in an overall reduction in air emissions from the Refinery due to the reduction in the volume of feedstock refined at the facility, cumulative criteria pollutant health risk (i.e., emissions from the Project plus other development in the vicinity of the Project Site) would continue to exceed regional air quality thresholds of significance, and this impact would remain cumulatively significant and unavoidable. The maximum annual average $PM_{2.5}$ concentration at both residential and worker receptors exceeded the significance threshold of 0.8 ug/m^3. $PM_{2.5}$ concentrations were highest in the immediate vicinity of highways and around the cement and aggregate materials handling operations located to the southwest of the facility. The highest residential receptor was located immediately adjacent to Interstate Highway 680, and nearly all $PM_{2.5}$ at that receptor was due to highway mobile source emissions. The highest worker receptor was at the Valley Relocation & Storage Moving Company located across Highway 4 from the cement and aggregate materials handling operations. Over 95 percent of the $PM_{2.5}$ at this receptor was from the two materials handling operations. The impact at other residential and worker receptors was below the threshold of 0.8 $\mu g/m^3$. Project $PM_{2.5}$ concentrations are negative (pre- Project $PM_{2.5}$ concentrations exceed post-Project $PM_{2.5}$ concentrations); therefore, implementation of this Project would reduce overall $PM_{2.5}$ concentrations. Additional emissions reductions from non-Project sources would be required to reduce the $PM_{2.5}$ concentration to below the significance threshold. Reductions from other sources are outside the purview of this Project; therefore, the impact on cumulative $PM_{2.5}$ concentration is significant and unavoidable.

Biological Resources

Impact BIO-8: Adverse impacts to special status species, protected habitats, and migratory corridors and nursery sites for native species as a result of a major spill would remain significant and unavoidable. Marathon would be required to update the Refinery's Facility Response Plan (FRP) and Spill Prevention, Control, and Countermeasure Plan (SPCC) to demonstrate preparedness to respond to vegetable oil and animal fat spills. However, there are limitations to thorough containment and cleanup of a major oil spill. As was determined in the Avon and Amorco EIRs certified by the SLC, even with specific procedures to protect sensitive biological resources in the Project vicinity, adverse impacts to special status species, protected habitats, and migratory corridors and nursery sites for native species as a result of a major spill would remain significant and unavoidable. The EIR imposes mitigation measures BIO-1b, BIO-1c and HAZ-1, which require updates and implementation of spill response plans, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

Impact BIO-9: Adverse impact to special status species, protected habitats, and migratory corridors and nursery sites for native species from introducing new nonindigenous aquatic species via ballast water and vessel biofouling to the San Francisco Bay Estuary waters remains significant and unavoidable. The EIR imposes mitigation measures BIO-9a but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

Hazards and Hazardous Materials

Impact HAZ-1: Increased vessel calls would increase the potential for corresponding accidental releases of renewable fuel or feedstocks which would be significant and unavoidable. The EIR imposes mitigation measures BIO-1b, BIO-1c and HAZ-1, which require updates and implementation of spill response plans, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

Water Quality

Impact HWQ-1: Consequences of a large spills could result in significant residual impacts. Though the probability of a serious spill would be minimized to the extent feasible with mitigation measures, a large spill could still occur and result in impacts on water quality that would be significant and unavoidable. The EIR imposes mitigation measures BIO-1b, BIO-1c and HAZ-1, which require updates and implementation of spill response plans, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

3. **Findings on Alternatives to the Martinez Renewable Fuels Project**

Alternatives Considered but Eliminated from Further Consideration

The County finds that each of the alternatives eliminated from further consideration in the Draft EIR is infeasible, would not meet most project objectives, and/or would not reduce or avoid significant impacts of the Project, for the reasons detailed in Chapter 5 of the Draft EIR.

Alternatives Analyzed in the EIR

In accordance with CEQA and the CEQA Guidelines, Chapter 5 of the Draft EIR evaluated a reasonable range of alternatives to the Martinez Renewable Fuels Project. The EIR's analysis examined the feasibility of each alternative, the environmental impacts of each alternative, and each alternative's ability to meet the project objectives described in Chapter 1, Section 1.2 of the EIR. In accordance with CEQA and the CEQA Guidelines, the alternatives analysis included an analysis of a no-project alternative and identified the environmentally superior alternative.

FINDING: The County certifies that it has independently reviewed and considered the information on alternatives provided in the Draft EIR and in the administrative record. For the reasons set forth below, the County finds that the alternatives either fail to avoid or substantially lessen the Project's significant impacts (and in some cases increase or create new significant and unavoidable impacts) or are "infeasible" as that term is defined by CEQA and the CEQA Guidelines.

The Draft EIR evaluated three alternatives to the Project:

• Alternative 1 – No Project Alternative
• Alternative 2 – Reduced Renewable Feedstock Throughput Alternative
• Alternative 3 – Green Hydrogen Alternative

Brief summaries of these alternatives and findings regarding these alternatives are provided below.

1) Alternative 1 – No Project Alternative

Under the No Project scenario, the proposed Renewable Fuels Project would not proceed. Rather, Refinery operations would resume as described in Section 2.4 of the Draft EIR. Current permits and entitlements for crude oil refining would remain unmodified and in effect, and the Refinery would operate under those current permits and entitlements. The Refinery's operations are currently permitted by the Bay Area Air Quality Management District to have a crude oil refining capacity of 161,000 barrels per day (bpd). For the 5 years prior to the submittal of land use and air permit applications for the Project, actual Refinery throughput averaged approximately 121,000 bpd. The Refinery would operate 24 hours a day, 7 days a week with an estimated 700 workers consisting of production and maintenance employees on rotating shifts and administrative staff. (See Draft EIR, Chapter 5, Section 5.2.1)

FINDING: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the No Project alternative infeasible. This alternative would not achieve most of the objectives of the proposed project, with the exception of maintaining quality jobs. Moreover, the No Project Alternative would result in the same impacts to aesthetics, biological resources, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, and public services as the proposed Renewable Fuels Project and would result in more severe impacts to air quality, energy use, greenhouse gas emissions, transportation, and utilities and service systems than the proposed Renewable Fuels Project. For these reasons, the County rejects this alternative.

2) Alternative 2 – Reduced Renewable Feedstock Throughput Alternative

This alternative would involve conversion of the Refinery from a crude oil processing facility to a facility for the refining of renewable fuels at a reduced capacity compared to the proposed Project. As noted in the Project Description (Section 2.5.2 of the Draft EIR), the proponent anticipates phasing in the Project over two years, with an interim throughput of 23,000 bpd. In the Reduced Renewable Feedstock Throughput alternative, renewable feedstock throughput would not increase beyond this interim maximum. Other components of the Project, including installation of equipment necessary for renewable fuels refining, decommissioning and demolition of crude oil processing units, and changes to pipelines at the Avon and Amorco marine oil terminals (MOTs), would be components of this alternative. The refinery would continue to operate 24 hours per day, 7 days per week, with a level of staffing comparable to the proposed Project (130 to 150 workers) on a rotating shift basis. (See Draft EIR, Chapter 5, Section 5.2.2)

FINDING: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the Reduced Renewable Feedstock Throughput alternative infeasible. By limiting renewable feedstock throughput, this alternative would generate fewer jobs, would result in a lower volume of renewable fuels being produced and brought to market to support the State's renewable energy goals, and would not achieve the Project objectives as well as the proposed project. For these reasons, the County rejects the Reduced Renewable Feedstock Throughput alternative as infeasible.

3) Alternative 3 – Green Hydrogen Alternative

In the Green Hydrogen alternative, green hydrogen would be used in the renewable fuels refining process. In contrast to the existing steam methane reforming technology that separates hydrogen atoms from hydrocarbon fuel molecules using the Refinery's existing infrastructure, green hydrogen uses electricity from renewable energy sources to produce hydrogen via electrolysis of water molecules into their constituent elements of hydrogen and oxygen. Under this alternative, the proposed throughput would not change from the proposed Project's throughput of 48,000 bpd of renewable feedstock, though green hydrogen from water electrolysis would be used in the refining process instead of the steam-methane reforming process. (See Draft EIR, Chapter 5, Section 5.2.3)

<u>FINDING</u>: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the Green Hydrogen alternative infeasible. While the Green Hydrogen alternative would meet many project objectives, this alternative would not meet the project objective of repurposing and reusing existing Refinery infrastructure. Instead, it would require installation of a new hydrogen plant and renewable energy source(s), such as wind turbines or photovoltaic panels, as a power source for the new hydrogen plant. The County has assumed, for purposes of evaluating this alternative, that the renewable energy source would be solar because wind farms are limited to the County's easternmost areas under General Plan policy (Policy 8-49). Because this alternative would require construction of a renewable energy source on-site, the developed footprint of the Site could increase with installation of solar panels on currently undeveloped lands at the Site. The need for a renewable energy source such as solar means that the Green Hydrogen alternative may have greater impacts on aesthetics, biological resources, and cultural and tribal resources than the proposed Project. A photovoltaic array of sufficient size to provide electricity to a new green hydrogen plant could create a new source of light and glare along the Site's marshes or shoreline. This expansion of infrastructure into largely natural areas outside of the Refinery equipment area would change the existing industrial appearance of the property and could interfere with views of Mt. Diablo from the shoreline, in conflict with County General Plan Goal 9-F and Policy 9-25. Further, among the alternatives evaluated in the EIR, the Green Hydrogen alternative would result in the greatest long-term impacts to biological resources as a result of modifying the natural environment to develop several hundred acres undeveloped acres for use as a photovoltaic array. Finally, the installation of renewable energy infrastructure on currently undeveloped land required by the Green Hydrogen alternative has the potential to disturb unknown historic archaeological and

cultural resources. For these reasons, the County rejects the Green Hydrogen alternative as infeasible.

Environmentally Superior Alternative

FINDING: While the County finds that the Reduced Renewable Feedstock Throughput Alternative is the environmentally superior alternative because it would not result in impacts greater than the proposed Project and would in many cases result in reduced impacts compared to the proposed Project, the County also finds that the Reduced Renewable Feedstock Throughput alternative is infeasible under Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3) because it would not meet many of the basis project objectives. The Reduced Renewable Feedstock Throughput alternative is infeasible because it would generate fewer jobs, result in a lower volume of renewable fuels being brought to market to support the State's renewable energy goals, and would not achieve the Project objectives as well as the proposed project. For these reasons, the County rejects the environmentally superior alternative as infeasible. The County further finds that of the remaining alternatives evaluated in the EIR, each has varying levels of impacts on different environmental resources, as noted in the Findings above, and none of the remaining alternatives is superior to the Project for CEQA purposes. Compared to the remaining alternatives, the Martinez Renewable Fuels Project provides the best available and feasible balance between maximizing attainment of the project objectives and minimizing significant environmental impacts, and the Project is the environmentally superior alternative among those options.

4. **Statement of Overriding Considerations**

As required under Public Resources Code section 21081 and CEQA Guidelines Section 15093, the County, having reviewed and considered the project EIR, all other written materials within the administrative record, and all oral testimony presented at public hearings and other public meetings on the project EIR, has balanced the benefits of the proposed project against the identified unavoidable adverse impacts associated with the project, and hereby adopts all feasible mitigation measures with respect to such impact, certifies the project EIR, and approves this project. After balancing the specific economic, legal, social, technological, and other benefits of the proposed project, the County has determined that the significant and unavoidable adverse impacts identified above are acceptable due to the following specific considerations in the record, which outweigh the unavoidable, adverse environmental impacts of the Martinez Renewable Fuels Project. Each of the considerations in the record, standing alone, is sufficient to support approval of the project, in accordance with CEQA.

The following legal requirements and benefits of the proposed project individually and collectively outweigh the potentially significant unavoidable adverse impacts for the following reasons:

1) The proposed project would repurpose the existing Marathon Martinez Refinery to a renewable fuels production facility allowing the continued operation of an existing industrial facility, preserving high quality jobs in the Martinez area, as well as, minimizing construction activities and related land use impacts associated with producing renewable fuels compliant with California LCFS.

2) The proposed project would reduce hazard impacts at the facility by eliminating further refining of crude oil, reducing the use and volumes of hazardous materials at the Marathon Martinez facility, and reducing the number of operating units at the Facility. Instead, the Facility would use non-hazardous renewable feedstocks as opposed to crude oil to produce transportation fuels.

3) The proposed project would result in large air quality benefits by reducing air emissions associated with the operation of the Martinez Facility. The emission reductions from the proposed project include nitrogen oxides (539.47 tons/year), sulfur dioxide (651.89 tons per year), carbon monoxide (598.64 tons per year), precursor organic compounds (POCs) (91.90 tons per year), particulate matter less than 10 microns in diameter (PM_{10}) (246.69 tons per year) and $PM_{2.5}$ (221.09 tons per year), providing large air quality benefits in the local Martinez and Bay Area. These emission reductions are associated with the shutdown of a number of refinery units, as well as emission reductions from marine vessels, employee vehicles, and trucks. Furthermore, by reducing emissions of air pollutants from existing conditions, the project will forward the goals of the Bay Area Air Quality Management District's 2017 Clean Air Plan. Specifically, the project would be consistent with the plan's Refinery Emissions Reduction Strategy by eliminating sources associated with petroleum refining, and with the plan's call for refineries to transition to clean energy companies by 2050.

4) The proposed project would result in a reduction in toxic air contaminants from the Martinez Facility, resulting in a reduction in cancer risk and chronic health impacts across all receptors within the local Martinez area. This reduction provides a beneficial health impact to all land uses adjacent to the Martinez Facility.

5) The project would provide emission reductions throughout the Bay area by reducing emissions from marine vessels, including nitrogen oxides (245.02 tons/year), sulfur dioxide (401 tons per year), carbon monoxide (4.62 tons per year), precursor organic

compounds (15.23 tons per year), PM_{10} (27.40 tons per year) and $PM_{2.5}$ (10.18 tons per year), providing a beneficial air quality impact in the Bay Area.

6) The proposed project would produce renewable fuels in compliance with California's Low Carbon Fuel Standard (LCFS) mandates, to help allow California to achieve substantial progress towards meeting its renewable energy goals. The LCFS was designed to reduce the State's reliance on petroleum-based fuels and encourage the use of less carbon-intensive fuels in the transportation sector. California officials have identified the LCFS as the centerpiece to the state's efforts to combat climate change, e.g., CARB's 2008 Climate Change Scoping Plan and its subsequent updates. Under California Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006, refineries are subject to regulations aimed at reducing California's global warming emissions and transitioning to a sustainable, low-carbon future (CARB 2021). The latest Update to the Climate Change Scoping Plan (CARB 2017) sets goals of a 40-percent GHG emission reduction below 1990 emission levels by 2030 and a substantial advancement toward the 2050 goal to reduce emissions by 80 percent below 1990 emission levels. Key provisions of AB 32 include the Low-Carbon Fuel Standard, which is intended to reduce California's dependency on petroleum by encouraging the provision of low-carbon and renewable alternative fuels, and the Cap-and-Trade Regulation, which discourages major sources of GHG emissions and encourages investment in cleaner, more efficient technologies. By increasing production of renewable fuels, the project will provide a mechanism for compliance with these provisions through providing facilities in California.

7) The proposed project would provide a direct benefit on climate change by decreasing greenhouse gas emissions (88,456 metric tons of CO_2e per year) from stationary mobile sources at the Martinez Facility, as well as mobile sources that visit the Facility. Governor Newsom's Executive Order N-79-20 states: "clean renewable fuels play a role as California transitions to a decarbonized transportation sector" and "to support the transition away from fossil fuels consistent with the goals established in this Order and California's goal to achieve carbon neutrality by no later than 2045, the California Environmental Protection Agency and the California Natural Resources Agency, in consultation with other State, local and federal agencies, shall expedite regulatory processes to repurpose and transition upstream and downstream oil production facilities..." The Governor's Order also directs CARB to "develop and propose strategies to continue the State's current efforts to reduce the carbon intensity of fuels beyond 2030 with consideration of the full life cycle of carbon. Additionally, the California Air Resources Board's November 19, 2020, "California's Greenhouse Gas Goals and Deep Decarbonization" presentation anticipates that biofuels will comprise 19 percent of the

transportation "fuel" sector by 2045." As a major producer of renewable fuels, the project would materially contribute to California's efforts to meet the goals of Executive Order N-79-20.

8) The proposed project would produce renewable fuels that significantly reduce the lifecycle generation of greenhouse gas emissions, as well as other criteria pollutants, including particulate matter, as compared to the manufacture and use of transportation fuels from fossil-fuel feedstocks.

9) The proposed project would reduce emissions from mobile sources by providing cleaner burning fuels in sources that use the renewable fuels, e.g., the Bay Area and California. These emission reductions provide a large air quality benefit as they would occur throughout California or wherever the renewable fuels are used.

10) The proposed project would result in beneficial impacts on energy demand by decreasing the electricity and natural gas demand from the Martinez Facility. Reducing natural gas and electricity consumption assists the public utilities to meet the state's Renewable Portfolio Standard.

11) As evaluated in Section 3.14 – Transportation of the EIR, the proposed project would be consistent with CEQA Guidelines Section 15064.3(b) by resulting in a reduction in vehicle miles travelled from both employee and truck trips.

12) Recycling organic wastes and by-products such as used cooking oils, rendering wastes, and other fats, oils, and greases has a number of environmental and economic benefits. These include reducing demand on landfill space, reducing the carbon footprint of fuels, and generating a second revenue stream from the same material. By accepting large quantities of recyclable fats, oils, and grease to be processed into renewable fuels, the project will help realize those benefits.

In balancing the benefits of the overall project described above with the proposed project's unavoidable and significant adverse environmental impacts, the County finds that the proposed project's benefits individually and collectively outweigh the unavoidable adverse impacts, such that these impacts are acceptable. The County further finds that substantial evidence presented in the FEIR supports adopting the FEIR despite the proposed project's potential adverse impacts.

B. **<u>Growth Management Element Performance Findings</u>**

1. <u>Traffic</u>: The traffic impacts have been reviewed in the July 27, 2021 Transportation Analysis provided by the applicant and are not expected to have any permanent negative impacts on local traffic patterns. The report was prepared in compliance with Measure C 1998 requirements. The project includes conversion of the existing Refinery from its production of fossil fuels to the production of renewable fuels, including renewable diesel, renewable propane, renewable naphtha, and, potentially, renewable jet fuel. The Project would not include any housing or surrounding retail. The Project would involve short-term construction activities and is not anticipated to create a significant increase in the number of permanent jobs at the Refinery. In this context, the Project is not expected to spur new regional population or employment growth and will not result in significant growth-inducing impacts.

2. <u>Water</u>: The Refinery currently consumes 3,100 to 3,300 million gallons of fresh water per year. The Project is expected to reduce the overall water use at the facility by about 70 percent or about 1,310 – 1,320 million gallons of fresh water per year. Therefore, the proposed Project would not require additional water and would decrease water use. Further, the proposed Project would not result in the relocation or construction of new or expanded public water facilities.

3. <u>Sanitary Sewer</u>: The Project would result in decreases in throughput, production and employment at the Refinery, which in turn would be anticipated to result in generation of a lower volume of waste as compared to prior Refinery operations. The Pretreatment Unit produces a wastewater stream that would require partial pretreatment prior to treatment in the existing wastewater treatment facility. Existing tanks would be utilized and repurposed for equalization and biological treatment of the waste stream. Since Marathon treats its wastewater generated from the facility, the project will have no impact on any public wastewater treatment provider.

4. <u>Fire Protection</u>: Refinery operators maintain internal fire response teams and systems for the developed areas of the Refinery. On-site fire suppression systems include fire pumps, foam systems, firefighting engines and trucks, and fire hydrants spaced 200 feet apart in refining process areas and tank farms. As a supplemental fire protection resource, the Refinery and other Bay Area refineries and industrial facilities are members of the Petrochemical Mutual Aid Organization. CCCFPD has in prior years been called to respond to incidents at the Refinery. Additionally, a portion of the Project Site is currently provided emergency fire and emergency medical technician response services by the Contra Costa County Fire Protection District. The closest operating fire station to the Refinery is Contra Costa Fire Station 9, located at 209 Center Avenue in the unincorporated community of Pacheco, approximately 1.6 miles southwest of the Refinery. Access to the Refinery from Station 9 is via public streets (Center Avenue, Marsh Drive, and Solano Avenue). The closest fire station to the Amorco MOT is Station 14 located at 521 Jones Street in the City of Martinez. Access to the terminal from the fire station is via an approximately 1.4-mile route along Alhambra Avenue to Marina Vista Avenue.

5. Public Protection: The Refinery maintains its own private security staff and security infrastructure for day-to-day Site security needs. Public safety services for the Refinery and two terminals are and would continue to be provided by the County Sheriff's Department, the Martinez Police Department and the California Highway Patrol. Police protections services within the City of Martinez are provided by the Martinez Police Department (MPD). As of 2020, the MPD included 33 sworn officers and four vacant positions. The Project would involve short-term construction activities and is not anticipated to create a significant increase in the number of permanent jobs at the Refinery. In this context, the Project is not expected to spur new regional population or employment growth and will not result in significant growth-inducing impacts. Since the project is not expected to induce population growth, no additional demand for public protection services is expected.

6. Parks and Recreation: Recreational facilities proximate to the Project Site include publicly-owned and publicly accessible parks and open spaces, as well as privately-owned lands on the Refinery property. Just east of the Refinery and Avon MOT are several hundred acres of undeveloped marshlands that include the Point Edith Wildlife Preserve, a 761-acre tidal area accessible to the public for wildlife viewing and hunting. The Preserve is managed by the California Department of Fish and Wildlife and located north of the Refinery's on-site marshlands. The closest Martinez City owned park to the Amorco MOT is Waterfront Park, located approximately 2,500 feet west of the property line of the terminal. Approximately 76 acres at the southern end of the Project Site is developed with a complex of recreational baseball, softball and soccer fields that are used by local sports clubs and teams but are part of the property owned by Marathon. The Project would involve short-term construction activities and is not anticipated to create a significant increase in the number of permanent jobs at the Refinery. In this context, the Project is not expected to spur new regional population or employment growth and will not result in significant growth-inducing impacts. Since the project is not expected to induce population growth, no additional demand for parks and recreation facilities is expected.

7. Flood Control and Drainage: The operating portions of the Project Site where modifications and/or construction is proposed are designated Zone X by the FEMA, which means that it is an area determined to be an area of minimal flood hazard. Project construction activities would not result in physical changes in these designated areas. Therefore, the Project would not create or substantially increase risks from flooding. Project activities are not expected to result in the construction of additional impervious surfaces that would substantially alter existing drainage patterns. There are no streams, rivers or other natural drainages within the Project Site that would be impacted by the construction of new units or equipment. Stormwater and surface runoff within the Project Site are already treated within the existing wastewater treatment plant and managed under a NPDES permit. Construction activities are not expected to substantially alter drainage patterns to impede or redirect flood flows. Thus, the project is not expected to impact the flood control or drainage systems or facilities in the County.

C. **Land Use Permit Findings**

1. The project shall not be detrimental to the health, safety, and general welfare of the County.

   Project Finding: The EIR for the proposed Project identified significant impacts that cannot be fully mitigated to less-than-significant levels with implementation of identified mitigation measures. These significant and unavoidable impacts include marine biological resources, hazards, and hydrology and water quality related to marine vessel accidents, and air quality related to rail and vessel emissions outside the San Francisco Bay Area Air Basin. The County may only approve the Project with significant adverse environmental impacts that are not mitigated if the agency finds that specific economic, legal, social, technological or other considerations, including provision of employment opportunities for highly trained workers, make imposition of mitigation measures or Project alternatives infeasible (CEQA Guidelines Section 15091). When a public agency determines that a project will have significant and unavoidable effects, Public Resources Code section 21081(b) requires that the public agency make findings of overriding considerations to demonstrate that economic, legal, social, technological, or other benefits of the project outweigh the significant environmental effects of the project. Accordingly, the County has made the requisite findings of overriding consideration and has found that the potential benefits of the project do in fact outweigh the environmental impacts. The project's benefits include providing jobs, improving air quality, reducing the amount of hazardous materials in the area, reduction in greenhouse gas emissions, and decrease energy (electricity and natural gas) demand at the facility.

   The EIR also identifies potentially significant impacts related to: construction-related air emissions; odor; marine and avian biological resources (non-spill related); cultural resources; seismicity; hazards; and tribal cultural resources. However, mitigation measures are identified for these impacts that ensure the Project will not cause a significant impact on the environment. The recommended mitigation measures are included within the Mitigation Monitoring and Reporting Plan, which describes the timing and responsible agency for monitoring compliance with all mitigation measures. The mitigation measures have also been incorporated into the recommended conditions of approval. Therefore, based on the forgoing, the Project will not be detrimental to health, safety, and general welfare of the County.

   The applicant has agreed to enter into a Community Benefits Agreement that provides financial support of workforce training and development and sustainability initiatives within Contra Costa County. This agreement directly supports the general welfare of the County and its residence through the commitment of one million dollars annually for a period of 10 years.

   As detailed in COA #32, the applicant is required to ensure the long-term reusability of the project site by implementing a Work Plan for the demolition and cleanup of the site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project is not detrimental to the long-term health, safety, or general welfare of the County and its residents.

2. The project shall not adversely affect the orderly development within the County or the community.

   Project Finding: All elements of the Martinez Refinery Renewable Fuels Project would be located within the existing boundaries of the refinery property already developed for refining operations. The primary elements of the project will be within the portion of the lands designated for Heavy Industry use by the County General Plan and zoned Heavy Industrial ("H-I") under the Contra Costa County Ordinance Code. Pursuant to these designations, refining and other manufacturing operations are allowed and are permitted uses, respectively. Based on the foregoing, the Project will not adversely affect the orderly development of property with the County.

   Condition of Approval #34 requires the applicant to ensure the long-term reusability of the project site by implementing a Work Plan for the demolition and cleanup of the site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project site is not burdened with obsolete equipment and hazardous materials that would prevent or hinder future development in the County.

3. The project shall not adversely affect the preservation of property values and the protection of the tax base within the County.

   Project Finding: The Refinery has operated as a facility for the production of petroleum-based fuels on the Project Site since its initial construction in 1913. The construction and operation of the project will result in the hiring of temporary and permanent employees at the refinery. Further, implementation of the Project will increase the assessed value of the refinery property, which would expand the County's tax base. The repurposing of the existing refinery to a renewable fuels production facility allows for the continued operation of an existing industrial facility and associated jobs and tax revenue. Furthermore, the Project includes modifications to the Avon and Amorco MOTs to facilitate their use for receipt and distribution of renewable feedstocks and fuels, consistent with supporting economic viability of the County's existing ports, wharves and shipping lanes. Thus, the proposal will not adversely affect the preservation of property values and the protection of the tax base within the County.

4. The project as conditioned shall not adversely affect the policy and goals as set by the General Plan.

   Project Finding: The Refinery equipment and related structures and facilities are on lands designated by the County General Plan as Heavy Industry (HI). While the County has jurisdiction over the land occupied by the associated onshore Refinery, the County does not have jurisdiction over the Avon Terminal. Nonetheless, the County's General Plan assigns a land use designation of Water (WA) to the Avon MOT, as the waters offshore of unincorporated lands bear relation to the County's long-term planning efforts. The pipeline between the Avon MOT and the Refinery is within a narrow strip of land designated as Open Space (OS). Pursuant to these designations, refining and other manufacturing operations are allowed and are permitted uses, respectively.

The Contra Costa General Plan contains the following relevant policies related to the project.

Countywide Polices

Policy 3-30 A variety of appropriately-sized, well-located employment areas shall be planned in order that industrial and commercial activities can contribute to the continued economic welfare of the people of the county and to the stable economic and tax bases of the county and the various cities. As the industrial project is located in an industrially developed area of the County, it is consistent with this policy.

Policy 3-42 Industrial development shall be concentrated in select locations adjacent to existing major transportation corridors and facilities. As the industrial project is located in an industrially developed area adjacent to major highways and waterway transportation in the County, it is consistent with this policy.

Policy 3-43 Industrial employment centers shall be designed to be unobtrusive and harmonious with adjacent areas and development. As the industrial project is located in an industrially developed area of the County, it is consistent with this policy.

Implementation Measure 3-b During project review, require that proposed uses on the edges of land use designations be evaluated to ensure compatibility with adjacent planned uses. As the industrial project is located in an industrially developed area of the County and is not proposing expansion, it is consistent with this policy.

Implementation Measure 3-d Review proposed land development projects for consistency with land use designations and relevant policies and standards of each element of the General Plan. The project has been evaluated with the land use designations and standards of the General Plan.

Policy 3-106 (Vine Hill/Pacheco Boulevard Area): The residential neighborhood east of I680 shall be buffered from the industrial/landfill-related uses. The project does not propose to expand the refinery use, thus the buffer shall remain.

Fire Protection Polices

Policy 7-58 Sheriff patrol beats shall be configured to assure minimum response times and efficient use of resources. No additional sheriff patrol services are expected since the refinery is an existing use.

Policy 7-62 The County shall strive to reach a maximum running time of 3 minutes and/or 1.5 miles from the first-due station, and a minimum of 3 firefighters to be maintained in all central business district (CBD), urban and suburban areas. Refinery operators maintain internal fire response teams and systems for the developed areas of the Refinery. On-site fire suppression systems include fire pumps, foam systems, firefighting engines and trucks, and fire hydrants spaced 200 feet apart in refining process areas and tank farms. As a supplemental fire protection resource, the Refinery and other Bay Area refineries and industrial facilities are members of the Petrochemical Mutual Aid Organization. CCCFPD has in prior years been called to respond to incidents at the Refinery.

Policy 7-72 Special fire protection measures shall be required in high risk uses (e.g., midrise and high-rise buildings, and those developments in which hazardous materials are used and/or stored) as conditions of approval or else be available by the district prior to approval. Refinery operators maintain internal fire response teams and systems for the developed areas of the Refinery. On-site fire suppression systems include fire pumps, foam systems, firefighting engines and trucks, and fire hydrants spaced 200 feet apart in refining process areas and tank farms. As a supplemental fire protection resource, the Refinery and other Bay Area refineries and industrial facilities are members of the Petrochemical Mutual Aid Organization. CCCFPD has in prior years been called to respond to incidents at the Refinery.

Policy 7-79 Local fire agencies shall be encouraged to identify and monitor uses involving the handling and storage of hazardous materials. As a supplemental fire protection resource, the Refinery and other Bay Area refineries and industrial facilities are members of the Petrochemical Mutual Aid Organization. CCCFPD has in prior years been called to respond to incidents at the Refinery.

Policy 7-136 The environmental review process shall be utilized to monitor the ability of area schools to serve development. No increase in population is expected from the project, thus additional area schools would not be required to serve the project.

<u>Vegetation and Wildlife Policies</u>

8-6 Significant trees, natural vegetation and wildlife populations generally shall be preserved. The project will not impact these resources.

8-9 Areas determined to contain significant ecological resources, particularly those containing endangered species, shall be maintained in their natural state and carefully regulated to the maximum legal extent. Acquisition of the most ecologically sensitive properties within the County by appropriate public agencies shall be encouraged. The environmental document evaluated ecological resources and identified mitigations that will mitigate impacts to them.

8-10 Any development located or proposed within significant ecological resource areas shall ensure that the resource is protected. Mitigation measures have been developed to protect ecological resources surrounding the site.

8-11 The County shall utilize performance criteria and standards which seek to regulate uses in and adjacent to significant ecological resource areas. Mitigation measures have been developed to protect ecological resources surrounding the site.

8-17 The ecological value of wetland areas, especially the salt marshes and tidelands of the bay and delta, shall be recognized. Existing wetlands in the County shall be identified and regulated. Restoration of degraded wetland areas shall be encouraged and supported wherever possible. Mitigation measures have been developed to protect wetland resources surrounding the site.

8-18 The filling and dredging of lagoons, estuaries, and bays which eliminate marshes and mud flats shall be allowed only for water-oriented projects. The project does not propose to dredge or fill waters in the County.

Scenic Resources

Policy 9-32 Major park lands shall be reserved to ensure that the present and future needs of the county's residents will be met and to preserve areas of natural beauty or historical interest for future generations. Apply the parks and recreation performance standards in the Growth Management Element. No population growth is expected from the implementation of the project, thus no additional park resources are needed.

Policy 9-35 Regional-scale public access to scenic areas on the waterfront shall be protected and developed, and water-related recreation, such as fishing, boating, and picnicking, shall be provided. The project will not impact public access to scenic areas on the waterfront since the refinery is existing.

9-D To preserve and protect areas of identified high scenic value, where practical, and in accordance with the Land Use Element Map. The project will not expand into any scenic resources.

9-F To preserve the scenic qualities of the San Francisco Bay/Delta estuary system and the Sacramento-San Joaquin River/Delta shoreline. The project will not expend into scenic resources on the waterfront. All development is located within the existing refinery facility.

9-13 Providing public facilities for outdoor recreation should remain an important land use objective in the county, as a method of promoting high scenic quality, for air quality maintenance, and to enhance outdoor recreation opportunities of all residents. The industrial project on a developed industrial site will not impact access to outdoor recreation.

9-24 The appearance of the county shall be improved by eliminating negative features such as non-conforming signs and overhead utility lines, and by encouraging aesthetically designed facilities with adequate setbacks and landscaping. Project development is proposed within the existing refinery. Obsolete equipment will be removed, consistent with the policy.

9-25 Maintenance of the scenic waterways of the county shall be ensured through public protection of the marshes and riparian vegetation along the shorelines and delta levees, as otherwise specified in this Plan. The project will not expand into scenic areas as the development will take place on the developed portion of the industrial property.

9-27 Physical and visual public access to established scenic routes shall be protected. The project is located within an existing private industrial facility and will not block physical or visual public access.

Implementation Measure 9-b Carefully study and review any development projects which would have the potential to degrade the scenic qualities of major significant ridges in the county or the bay and delta shoreline. The project is located within an existing industrial facility and will not further detriment the delta shoreline.

<u>Noise Polices</u>

Policy 11-1 establishes the acceptability of proposed new land uses within existing noise-impacted areas in accordance with the State of California General Plan Guidelines. The maximum exterior noise level considered to be "normally acceptable" for single-family residential uses is 60-dBA Ldn, and noise levels of up to 70-dBA Ldn are considered to be "conditionally acceptable." The maximum exterior noise level considered to be "normally acceptable," without condition, for industrial uses is 70-dBA Ldn. This policy does not apply to temporary noise levels, such as from construction. The project is not expected to create noises that would exceed thresholds within surrounding properties.

Policy 11-8 states that construction activities shall be concentrated during the hours of the day that are not noise-sensitive for adjacent land uses and should be commissioned to occur during normal work hours of the day to provide relative quiet during the more sensitive evening and early morning periods. These limitations would be included as conditions of approval and the facility operates in an industrial area located away from other land uses.

5. The project shall not create a nuisance and/or enforcement problem within the neighborhood or community.

   <u>Project Finding</u>: The construction of the new equipment units would take place within the currently developed portions of the Project Site and are not expected to introduce nuisance sources. The EIR for the project included an assessment of the potential for the Project to cause a public nuisance by subjecting surrounding land uses (receptors) to objectionable odors. The primary source of odors from pre-Project operations are the treatment of sour gas streams, the Sulfur Recovery Unit (SRU), the Sulfuric Acid Plant (SAP), storage of crude oil and the wastewater treatment plant. The SRU, SAP, and crude oil storage would be shut down as part of this Project resulting in a reduction of odors. The wastewater treatment plant will be upgraded with a new Moving Bed Biological Reactor unit. Odors from wastewater are often created when treatment systems are under

designed or there is poor control of operational variables. The new wastewater treatment plant will have an equalization tank to provide a consistent feed to the plant creating fewer process swings and better control of process operating limits. The controls for chemical addition and outfall would be automated with updated technology that is more reliable. The combination of these upgrades will result in reduced odor from the wastewater treatment plant.

Potential new sources of odor are the storage of renewable feedstock, including tallow. In order to determine the level of potential odor and whether controls would be needed, Marathon visited three facilities where fat, oils, and grease were stored. Noticeable odors were not observed at these facilities and odor control technologies used at these sites were incorporated into the design for this Project. Odor management controls including carbon canisters, nitrogen blanketing of storage tanks and a vapor recovery system would be used to reduce odors from the storage tanks and loading and unloading activities. An operational Odor Management Plan (OMP) will be developed and implemented, intended to become an integrated part of daily operations at the Facility and other sites, so as to prevent any objectionable offsite odors and effect diligent identification and remediation of any potential objectionable odors generated by the facility and associated sites. The Odor Management and Control Plan (OMCP) will include continuous evaluation of the overall system performance, identification of trends to provide an opportunity for improvements to the plan, and updating the odor management and control strategies, as necessary.

The clean air strategy of the BAAQMD includes the preparation of plans for the attainment of ambient air quality standards, adoption and enforcement of rules and regulations concerning sources of air pollution, and issuance of permits for stationary sources of air pollution. The facility would implement control measures for emissions that would be incorporated into applicable permits issued by the BAAQMD and enforced by the district.

Transportation conditions during construction were analyzed assuming the maximum number of construction trips. The traffic analysis in Section 3.14, Transportation, of the DEIR, is based on a construction schedule that presumes a total of 1,400 workers, most working day shifts. During construction, the number of truck trips would be estimated at between 60 and 310 trips per day, depending on timing and phasing. A number of trips would be used for deliveries and distribution of petroleum coke and products manufactured at the Refinery. Project truck trips would be scheduled to avoid peak travel times along major highways, and full road closures would not be expected.

Due to the number of employees expected during Project construction, a short-term increase in vehicle trips and construction traffic would last for the duration of construction. The transportation impacts during Project construction would be less than significant. The Project would not require an increase in the number of workers required to operate the Refinery, and no long-term operational traffic impacts would be expected. Therefore, the proposal will not create a nuisance and/or enforcement problem within the neighborhood or community.

Condition of Approval #34 requires the applicant to ensure the long-term reusability of the project site by implementing a Work Plan for the demolition and cleanup of the site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project site does not become a nuisance and reduces the risk of hazardous materials impacting neighboring communities.

6. The project as conditioned shall not encourage marginal development within the neighborhood.

   Project Finding: The Martinez Refinery Renewable Fuels Project will be primarily located in areas zoned H-I under the County Ordinance Code and designated Heavy Industry in the County General Plan. The open waters of the Carquinez Strait and lower Suisun Bay are offshore to the north of the Project site. Onshore, undeveloped lands on and around the Project site include marsh habitats between open water and onshore facilities and ruderal/upland habitat onshore between the marsh habitat and developed lands. Developed lands in the immediate and general vicinity of the Project site include a variety of residential, commercial, industrial, and public uses. Just east of the Refinery and Avon MOT are several hundred acres of undeveloped marshlands. This area includes the Point Edith Wildlife Preserve, a 761-acre tidal area accessible to the public for wildlife viewing and hunting. The unincorporated residential community of Clyde is east of the Refinery's on-site marshlands, on the opposite side of Port Chicago Highway from the Refinery's eastern property line. The Contra Costa Water District's Mallard Reservoir, and multiple complexes of light industrial warehouse buildings are also located east of the Project site. The refinery will not alter its use of the buffer zones. The proposal is intended to repurpose the existing refinery and would not expand development on the site. Therefore, it is not expected that the project would encourage marginal development within the neighborhood.

7. That special conditions or unique characteristics of the subject property and its location or surroundings are established.

   Project Finding: The Martinez refinery has existed in its present location for more than 100 years and is one of the few areas in the County suitable for the proposed project. The project areas are zoned Heavy Industrial District (H-I) by the County Ordinance Code. This designation allows a permitted use of oil refining and other manufacturing operations. The project will not result in any changes in the existing use of the refinery in that propane and butane are both already produced at the facility. Unique characteristics of the project have been reviewed in the EIR, including geologic characteristics described in the geotechnical investigation conducted by Hultgren-Tillis Engineers, the Biological Technical Report prepared by ERM Worldwide Group Ltd, and aesthetic characteristics identified in the project plans and satellite imagery. Any special conditions or unique characteristics have been fully evaluated and established.

II. CONDITIONS OF APPROVAL FOR COUNTY FILE #CDLP20-02046:

Land Use Permit Approval

1. This Land Use Permit is APPROVED to repurpose the existing Refinery for production of fuels from renewable sources rather than from crude oil.

2. The Land Use Permit approval described above is granted based generally on the following information and documentation:

    - Land Use Permit application submitted to the Department of Conservation and Development, Community Development Division (CDD) on September 16, 2020;
    - Project plans prepared by Marathon Petroleum Corporation, received September 15, 2021;
    - Martinez Refinery Renewable Fuels Project Draft Environmental Impact Report dated October 2021;
    - Martinez Refinery Renewable Fuels Project Final Environmental Impact Report dated March 2022;
    - 2013 Tesoro Amorco Marine Oil Terminal Lease Consideration Environmental Impact Report prepared by TRC Solutions for California State Lands Commission;
    - 2015 Tesoro Avon Marine Oil Terminal Lease Consideration Environmental Impact Report prepared by TRC Solutions for California State Lands Commission;
    - Biological Technical Report Martinez Renewable Fuels Project prepared by ERM Worldwide Group Ltd for Marathon Petroleum Corporation dated July 27, 2021;
    - Martinez Renewable Fuels Project Hazards and Hazardous Materials Technical Analysis prepared by Tesoro Refining & Marketing Company LLC, dated July 27, 2021;
    - Martinez Renewable Fuels Project Air Quality and Greenhouse Gas Technical Analysis prepared by Ashworth Leininger Group and Barr Engineering Company dated January 2022;
    - Martinez Renewable Fuels Project Noise Technical prepared by Marathon Petroleum Corporation dated July 27, 2021;
    - Martinez Renewable Fuels Project Hazards and Hazardous Materials Technical Analysis prepared by Marathon Petroleum Corporation dated July 2021;

- Geotechnical Investigation, Martinez Renewable Fuels Project, Marathon Refinery, Martinez, California prepared by Hultgren-Tillis Engineers dated March 12, 2021; and

- Martinez Renewable Fuels Project CEQA Transportation Assessment prepared by Tesoro Refining & Marketing Company LLC dated July 27, 2021.

Initial Compliance Report Prior to Submittal of Application for a Building Permit

3. **Prior to submittal of an application for or issuance of a building permit,** the applicant shall submit a report addressing compliance with the conditions of approval, for review and approval of the CDD. The report shall list each condition followed by a description of what the applicant has provided as evidence of compliance with that condition. Unless otherwise indicated, the applicant will be required to demonstrate compliance with the conditions of this report prior to issuance of construction permits. The Zoning Administrator may reject the report if it is not comprehensive with respect to applicable requirements for the requested permit. The deposit for review of the Compliance Report is $2,000.00; the actual fee shall be time and materials.

4. At least 60 days prior to commencement of construction-related activities, issuance of grading permits, or issuance of building permits, whichever occurs first, Marathon shall provide the County with an initial deposit of $10,000.00 to cover costs of mitigation monitoring. Marathon shall be responsible for providing adequate funding to cover all eventual costs of mitigation monitoring.

5. The applicant shall enter into an Indemnification Agreement with the County, and the applicant shall indemnify, defend (with counsel reasonably acceptable to the County), and hold harmless the County, its boards, commissions, officers, employees, and agents (collectively "County Parties") from any and all claims, costs, losses, actions, fees, liabilities, expenses, and damages (collectively, "Liabilities") arising from or related to the project, the applicant's land use permit application, the County's discretionary approvals for the project, including but not limited to the County's actions pursuant to the California Environmental Quality Act and planning and zoning laws, or the construction and operation of the project, regardless of whether those Liabilities accrue before or after project approval.

General Provisions

6. Any deviation from or expansion beyond the limits of this permit approved under this application may require the filing and approval of a request for modification of the Land Use Permit.

7. During construction, a publicly visible sign shall be posted on the property with the telephone

number and person to contact regarding construction-related complaints. This person shall respond and take corrective action within 24 hours. The CDD phone number to call in complaints shall also be visible to ensure compliance with applicable regulations.

8. The conditions contained herein are continuing obligations of the applicant, their agents, lessees, survivors, and successors, throughout the life of this permit.

9. The site shall be maintained in good condition over the term of the permit. This shall include keeping the structures graffiti-free. The facility, including all fences and walls surrounding the facility, and all other fixtures and improvements on a facility site, must be maintained and repainted as often as necessary to prevent fading, chipping, or weathering of paint.

10. At least 15 days prior to the issuance of a building permit, the developer shall demonstrate compliance with the debris recovery program, which requires at least 50 percent of the jobsite debris generated by construction projects of 5,000 square feet or greater to be recycled, or otherwise diverted from landfill disposal.

Air Quality

11. The facility shall not be used to refine or transfer palm oil.

12. The following Bay Area Air Quality Management District, Basic Construction mitigation measures and Additional Best Practices shall be implemented during project construction and shall be included on all construction plans:

    The permittee shall implement the following Basic Construction Mitigation Measures during construction of the Project:

    - All exposed surfaces (e.g., parking areas, staging areas, soil piles, graded areas, and unpaved access roads) shall be watered two times per day.
    - All haul trucks transporting soil, sand or other loose material off-site shall be covered.
    - The permittee shall not cause or allow track-out at any active exit from the site onto an adjacent paved public roadway or shoulder of a paved public roadway that exceeds cumulative 25 linear feet and creates fugitive dust visible emissions. All visible mud or dirt track-out onto adjacent public roads shall be removed using wet power vacuum street sweepers within 4 hours of when the owner/operator identifies such excessive track-out. The use of dry power sweeping is prohibited.
    - All vehicle speeds on unpaved roads shall be limited to 15 miles per hour.
    - All roadways, driveways, and sidewalks to be paved shall be completed as soon as possible. Building pads shall be laid as soon as possible after grading unless seeding or soil binders are used.
    - Idling times shall be minimized either by shutting equipment off when not in use or reducing the maximum idling time to 5 minutes (as required by the California airborne

toxics control measure Title 13, Section 2485 of California Code of Regulations). Clear signage shall be provided for construction workers at all access points.

- All construction equipment shall be maintained and properly tuned in accordance with manufacturer's specifications. All equipment shall be checked by a certified mechanic and determined to be running in proper condition prior to operation.
- Post a publicly visible sign with the telephone number and person to contact at the Lead Agency regarding dust complaints. This person shall respond and take corrective action within 48 hours. The Air District's phone number shall also be visible to ensure compliance with applicable regulations.
- Monitor the extent of the trackout at each active exit from the site onto a paved public road at least twice during each workday, at times when vehicle traffic exiting the site is most likely to create an accumulation of trackout, or as otherwise specified by the Air District.
- Document the active exit locations monitored each workday.
- Document each occasion when the trackout exceeds cumulative 25 linear feet and all trackout control and cleanup actions initiated as a result of the above monitoring.
- Maintain these records for at least five years, in electronic, paper hard copy or log book format, and make them available to the Air District upon request.

The permittee shall implement the following Additional Best Practices measures during construction of the Project:

- All exposed surfaces shall be watered at a frequency adequate to maintain minimum soil moisture of 12 percent. Moisture content can be verified by lab samples or moisture probe.
- All excavation, grading, and/or demolition activities shall be suspended when average wind speeds exceed 20 mph.
- Wind breaks (e.g., trees, fences) shall be installed on the windward side(s) of actively disturbed areas of construction. Wind breaks should have at maximum 50 percent air porosity.
- Vegetative ground cover (e.g., fast-germinating native grass seed) shall be planted in disturbed areas as soon as possible and watered appropriately until vegetation is established.
- The simultaneous occurrence of excavation, grading, and ground-disturbing construction activities on the same area at any one time shall be limited. Activities shall be phased to reduce the amount of disturbed surfaces at any one time.
- All trucks and equipment, including tires, shall be washed off prior to leaving the site.
- Site accesses to a distance of 100 feet from the paved road shall be treated with a 6-to-12-inch compacted layer of wood chips, mulch, or gravel.
- Sandbags or other erosion control measures shall be installed to prevent silt runoff to public roadways from sites with a slope greater than one percent.
- Only Tier 4 engines shall be used when practicable for construction equipment and zero-emission equipment as available.

(Mitigation Measure Air Quality 1a)

13. The following air emissions reduction BMPs shall be implemented to the maximum extent practicable by the applicant and construction contractors. The measures shall be incorporated into all construction contracts related to the Project.
    - Provide the necessary infrastructure to support the zero and near-zero emission technology vehicles and equipment that will be operating on-site. Necessary infrastructure may include the physical (e.g., needed footprint), energy, and fueling infrastructure for construction equipment, on-site vehicles, and medium-heavy and heavy-heavy duty trucks.
    - Portable equipment used during construction should be powered by electricity from the grid or onsite renewable sources, instead of diesel-powered generators.
    - All off-road diesel-powered equipment used during construction shall be equipped with Tier 4 or cleaner engines, except for specialized construction equipment in which Tier 4 engines are not available. In place of Tier 4 engines, off-road equipment can incorporate retrofits such that emission reductions achieved equal or exceed that of a Tier 4 engine.
    - All off-road equipment with a power rating below 19 kilowatts (e.g., plate compactors, pressure washers), used during project construction shall be battery powered.
    - All heavy-duty trucks entering the construction site, during the grading and building construction phases shall be model year 2014 or later, to the maximum extent practicable. All heavy-duty haul trucks shall also meet CARB's lowest optional low-NOx standard starting in the year 2022, to the maximum extent practicable.

    (Minimization and Measure AQ-1b)

14. During the construction phase of the Project, the operational Odor Management and Control Plan (OMCP) shall be developed and implemented upon commissioning of the renewable fuels processes, intended to become an integrated part of daily operations at the Facility and other sites, so as to prevent any objectionable offsite odors and effect diligent identification and remediation of any potential objectionable odors generated by the facility and associated sites. The plan shall outline equipment that is in place and procedures that facility personnel shall use to address odor issues, facility wide. The OMCP shall include continuous evaluation of the overall system performance, identification of trends to provide an opportunity for improvements to the plan, and updating the odor management and control strategies, as necessary. This plan shall be retained at the facility for County or other government agency inspection upon request. The following practices shall be included in the OMCP to reduce the potential of objectionable odors from the storage of renewable feedstocks, operation of the wastewater treatment plant, and any other odor generating activity:
    - Develop operating procedures to inspect and evaluate the effectiveness of odor control equipment and operation of the wastewater treatment plant.
    - Inspections to be conducted on a semi-annual basis.
    - If there are fewer than an average of five confirmed complaints per year during the first 3 years of operation, then the inspection frequency can be reduced to an annual basis.

- If there are more than five confirmed complaints in any single year, then the application shall develop additional mitigation strategies in consultation with the BAAQMD.
- In the event that odor complaints are reported, the permittee shall immediately take action to prevent repeat complaints. The permittee shall also develop and implement remedial odor mitigation strategies in consultation with the BAAQMD and County.

Prepare an annual evaluation report of the overall system performance, identifying any trends to provide an opportunity for improvements to the plan, and updates to the odor management and control strategies, as necessary. The report shall be provided to the County for review and approval.
(Mitigation Measure AQ-2)

Biological Resources

15. The following measures shall be included on all plans and employed by Marathon and its contractors to avoid and minimize impacts to water quality and other beneficial characteristics of wetlands at the Project Site.
    - All renovation personnel shall receive environmental awareness training provided by a County approved qualified biologist. The training shall provide information about special-status species potentially occurring in the Project area, measures being implemented to avoid impacts to the species, and procedures to follow should a listed species be encountered during routine activities. Training shall be conducted to assure understanding by both Spanish and English speakers. Training materials and the qualified biologist's resume shall be submitted to County staff for approval 2 weeks prior to program initiation.
    - No debris, soil, silt, sand, cement, concrete or washings thereof, or other construction-related materials or wastes, oil or petroleum products, or other organic or earthen material shall be allowed to enter into or be placed where it may be washed by rainfall or runoff into marshes or open water/ditches adjacent to the work areas.
    - All personnel and their equipment shall be required to stay within the designated construction area to perform job-related tasks and shall not be allowed to enter wetlands, drainages and habitat of listed species.
    - Pets shall not be allowed in or near the construction area.
    - Firearms shall not be allowed in or near the construction area, except for armed Marathon security officers who may periodically patrol work sites. No intentional killing or injury of wildlife shall be permitted.
    - The construction site shall be maintained in a clean condition. All trash (e.g., food scraps, cans, bottles, containers, wrappers, cigarette butts and other discarded items) shall be placed in closed containers and properly disposed off-Site.
    - After construction is completed, final cleanup shall include removal of all stakes, temporary fencing, flagging and other refuse generated by construction. Vegetation shall not be removed or disturbed in the cleanup process

    (Mitigation Measure BIO-1a)

16. The following measures shall be included on all plans and employed by Marathon and its contractors. Marathon and its contractors shall be responsible for structure operations in a manner that minimizes the risk of spills or the accidental discharge of fuels or hazardous materials. Marathon and its contractors shall, at a minimum, ensure that:
    - All employees handling fuels and other hazardous materials are properly trained.
    - All equipment is in good operating order and inspected regularly.
    - Hazardous materials, including chemicals, fuels and lubricating oils, shall not be stored within 200 feet of a wetland or water body. This applies to storage of these materials and does not apply to normal operation or use of equipment in these areas.
    - If refueling is needed on-Site, it will occur at least 100 feet from a surface water feature, and in a designated refueling area with secondary containment/plastic sheeting and a spill containment kit.

    (Mitigation Measure BIO-1b)

17. The following measures shall be included on all plans and employed by Marathon and its contractors. In the event of an accidental spill, the Facility Oil Spill Contingency Plan shall be implemented. Site-specific provisions shall be listed on the Safe Work Permit and included within the job plan maintained on-Site.

    At a minimum, Marathon and its contractors shall:
    - Ensure that each construction crew (including clean-up crews) has sufficient supplies of absorbent and barrier materials on-Site to allow the rapid containment and recovery of spilled materials, and that each construction crew knows the procedure for reporting spills.
    - Ensure that each construction crew has sufficient tools and material on Site to stop leaks.
    - Know the contact names and telephone numbers for all Marathon Martinez Refinery contacts and local, state and federal agencies (including, if necessary, the U.S. Coast Guard and the National Response Center) that might need to be notified in the event of a spill.
    - Follow the requirements of those agencies in cleaning up the spill, excavating and disposing soils or other materials contaminated by a spill, and collecting and disposing waste generated during spill cleanup

    (Mitigation Measure BIO-1c)

18. The Project shall adhere to and implement the requirements of the respective existing SWPPP for the Marathon Martinez Refinery, Avon Marine Terminal and Amorco Marine Terminal during Project construction. Applicable measures in each SWPPP shall be incorporated into the construction plans by a qualified specialist and implemented prior to construction.
    (Mitigation Measure BIO-1d)

19. The following work restrictions shall be included on all plans that include in-water work, and employed by Marathon and its contractors:
    - To the extent feasible, in-water work shall be performed between 30 minutes after sunrise and 30 minutes before sunset.
    - In-water work activity shall only occur during the work window specified by the NMFS and CDFW for avoidance of potential impacts to fish species in this region of the San Francisco Bay Estuary, August 1 to November 30. If in-water work outside this time period is required,

the work window may be adjusted through coordination with the CDFW, NMFS and USFWS.
(Mitigation Measure BIO-1e)

20. The following measures shall be employed by Marathon and its contractors. The measures shall be included as recommended practices incorporated into all construction contracts related to the Project. The number of round trips made by barges during construction shall be limited to the extent feasible. Barge and support vessels shall transit through the shallows at a no-wake-producing speed to minimize disturbance to bottom sediments. Anchoring shall be minimized to the extent possible.
(Mitigation Measure BIO-1f)

21. Marathon and its contractors shall clearly demarcate the limits of work in the field. All Project-related activity shall be confined to the designated work areas; no entry into adjacent areas shall be allowed by Project personnel. Upon Project completion, material used to mark the work boundary shall be removed.
(Mitigation Measure BIO-1g)

22. Marathon and its contractors shall implement measures to ensure that boots, clothing, vehicles and equipment are free of soils and plant parts prior to entering work areas.
(Mitigation Measure BIO-1h)

23. Focused surveys for soft-bird's beak shall be conducted by a qualified biologist each year during the appropriate blooming period (June 1 through September 30) prior to construction to confirm its absence. Locations of rare plants in proposed construction areas will be recorded using a GPS unit and flagged for avoidance. A qualified biologist shall monitor construction activities occurring in the vicinity of the flagged plants to ensure that no direct or indirect impacts occur.
(Mitigation Measure BIO-1i)

24. No more than 5 days prior to construction during the nesting bird season (February 1 through September 15), a qualified biologist shall conduct a survey for nesting birds. If work within an area lapses for more than 14 days during the nesting season, the survey shall be repeated. The survey shall encompass all work areas and those areas within a buffer of 250 feet for passerines, 500 feet for small raptors, and 1,000 feet for large raptors. Where accessible, the location of active nests will be recorded using a handheld global-positioning system unit. Should an active nest be discovered, a biological monitor will be required on-Site during construction activities that could cause disturbance of the nest. The biologist may allow work to continue if they determine that the work activity is not likely to cause nest disturbance. The biological monitor shall have the authority to stop work should a nesting bird display signs of agitation. The qualified biologist conducting the nesting surveys should prepare a report that provides details about the nesting outcome and the removal of buffers. This report should be submitted to the County's Department of Conservation and Development for review and approval prior to the time that buffers are removed.
(Mitigation Measure BIO-1j)

25. Prior to construction occurring during the rail nesting season (February 1 through August 31) within 700 feet of suitable rail habitat, surveys shall be conducted for California Ridgway's rail and California black rail in accordance with the USFWS Survey protocol for California Ridgway's rail. Surveys should be initiated between January 15 and February 1. For each survey station, four surveys are to be conducted. Surveys should be spaced at least two weeks apart and should cover the time period from the date of the first survey through the end of March or mid-April. If California Ridgway's or California black rails are detected during the survey, no work within 700 feet of the rail calling centers (identified via compass bearing and distance estimate during surveys) shall occur between February 1 and August 31, unless otherwise approved by USFWS and CDFW.
    (Mitigation Measure BIO-1k)

26. The following mitigation measure shall be implemented during all on-going business operations and shall be included as part of contractual agreement language to ensure that contract vessels are informed of all on-going operational responsibilities. Marathon shall update pre-arrival document materials and instructions sent to tank vessels agents/operators scheduled to arrive at the Marine Terminal with the following information and requests:
    - Available outreach materials regarding the Blue Whales and Blue Skies incentive program.
    - Whale strike outreach materials and collision reporting from NOAA.
    - Request extra vigilance by ship crews upon entering the traffic separation scheme shipping lanes approaching San Francisco Bay and departing San Francisco Bay to aid in detection and avoidance of ship strike collisions with whales.
    - Inform all vessel traffic of vessels 300 gross registered tons or larger to reduce speeds to 10-knots when transiting within the designated Vessel Speed Reduction zones.
    - Request compliance to the maximum extent feasible (based on vessel safety) with the 10-knot speed reduction zone. Understand and agree that decisions concerning safe navigation and maneuvering of participating vessels remain entirely with ship masters and crew.
    - Encourage participation in the Blue Whales and Blue Skies incentive program.

    (Mitigation Measure BIO-7a)

27. Marathon Refining and Marketing Company, LLC (Marathon) shall conduct and support the following activities to further the understanding of vessel strike vulnerability of sturgeon in San Francisco, San Pablo, and Suisun Bays and the Carquinez Strait. The support shall be based on criteria that establish Marathon's commensurate share taking into account the increase in vessel calls to the Avon and Amorco Marine Oil Terminals. Support shall include coordination with CDFW and Research Sturgeon to ensure appropriate messaging on information flyers suitable for display at bait and tackle shops, boat rentals, fuel docks, fishing piers, ferry stations, dockside businesses, etc. to briefly introduce interesting facts about the sturgeon and research being conducted to learn more about its requirements and how the public's observations can inform strategies being developed to improve fisheries habitat within the estuary.
    (Mitigation Measure BIO-7b)

28. Marathon Refining and Marketing Company, LLC (Marathon) shall continue to participate and assist in funding ongoing and future actions related to nonindigenous aquatic species (NAS) as described in Mitigation Measure BIO-9B of the Tesoro Avon Marine Oil Terminal Lease Consideration Project Final Environmental Impact Report (FEIR) and Mitigation Measure BIO-7b of the Amorco Marine Terminal FEIR. The level of funding shall be revisited through a cooperative effort between California State Lands Commission staff, the DWR, CDFW, and Marathon, and shall be based on criteria that establish Marathon's commensurate share NAS actions costs taking into account the increase in vessel calls to the Avon and Amorco Marine Oil Terminals.
    (Mitigation Measure BIO-9a)

Cultural and Archeological Resources

29. The following Mitigation Measures shall be implemented during project related ground disturbance, and shall be included on all construction plans:

    a. All construction personnel, including operators of equipment involved in grading, or trenching activities will be advised of the need to immediately stop work if they observe any indications of the presence of an unanticipated cultural resource discovery (e.g. wood, stone, foundations, and other structural remains; debris-filled wells or privies; deposits of wood, glass, ceramics). If deposits of prehistoric or historical archaeological materials are encountered during ground disturbance activities, all work within 50 feet of the discovery shall be redirected and a qualified archaeologist, certified by the Society for California Archaeology (SCA) and/or the Society of Professional Archaeology (SOPA), shall be contacted to evaluate the finds and, if necessary, develop appropriate treatment measures in consultation with the County and other appropriate agencies. If the cultural resource is also a tribal cultural resource (TCR) the representative (or consulting) tribe(s) will also require notification and opportunity to consult on the findings.

       If the deposits are not eligible, avoidance is not necessary. If eligible, deposits will need to be avoided by impacts or such impacts must be mitigated. Upon completion of the archaeological assessment, a report should be prepared documenting the methods, results, and recommendations. The report should be submitted to the Northwest Information Center and appropriate Contra Costa County agencies.

    b. Should human remains be uncovered during grading, trenching, or other on-site excavation(s), earthwork within 30 yards of these materials shall be stopped until the County coroner has had an opportunity to evaluate the significance of the human remains and determine the proper treatment and disposition of the remains. Pursuant to California Health and Safety Code Section 7050.5, if the coroner determines the remains may those of a Native American, the coroner is responsible for contacting the Native American

Heritage Commission (NAHC) by telephone within 24 hours. Pursuant to California Public Resources Code Section 5097.98, the NAHC will then determine a Most Likely Descendant (MLD) tribe and contact them. The MLD tribe has 48 hours from the time they are given access to the site to make recommendations to the land owner for treatment and disposition of the ancestor's remains. The land owner shall follow the requirements of Public Resources Code Section 5097.98 for the remains.

c. In the event the Project design changes, and ground disturbance is anticipated beyond the Area of Potential Effect, as it is currently defined by the Cultural Resources Inventory Reports, further surveys shall be conducted in those new areas to assess the presence of cultural resources. Any newly discovered or previously recorded sites within the additional survey areas shall be recorded (or updated) on appropriate Department of Parks and Recreation (DPR) 523-series forms. If avoidance of these cultural resources is not feasible then an evaluation and/or data recovery program shall be drafted and implemented.

(Mitigation Measure CR-1)

Geology and Geotechnical Report

30. Prior to issuance of a grading or building permit for the equipment changes associated with the Project, the Applicant shall submit a final geotechnical evaluation report prepared by a licensed engineer, for approval by the Department of Conservation and Development, Peer Review Geologist, along with payment for the peer review fee. The report shall specify final recommendations for seismically and structurally sound installation of new structures, equipment and foundations in accordance with the California Building Code standards in effect at the time the permit application is submitted. Construction drawings submitted with the building permit application shall include appropriate detail to demonstrate compliance of the Project with the standards of the applicable California Building Code.
(Mitigation Measure GEO-2)

Hazards and Hazardous Materials

31. The permittee shall comply with mitigation measures as outlined in the Operational Safety/Risk of Accident sections of the EIRs for both Amorco and Avon MOTs and as incorporated by reference into the leases as regulatory (lease) conditions. These measures include CLSC established requirements for preventative maintenance, including periodic inspection of all components related to transfer operations pipelines. The permittee shall comply with those requirements, as well as with the CSLC’s operational requirements, including Article 5.5 Marine Terminal Oil Pipelines 17 (California Code of Regulations, Title 2, Sections 2560-2571). The requirements, which are discussed in detail in the Avon and Amorco EIRs, are as follows:

- Installation of Remote Release Systems
- Maintaining of Tension Monitoring Systems
- Maintaining of Allision Avoidance Systems
- Development of a Fire Protection Assessment
- Participation in USCG Ports and Waterways Safety Assessment Workshops
- Response to any Vessel Spills near the Project

Prior to Project operations, the permittee shall complete routine inspection, testing and maintenance of all equipment and systems conducted in accordance with manufacturers' recommendations and industry guidance, as well as consideration of for general industry guidance on effective maintenance of critical equipment at the MOT.
(Mitigation Measure HAZ-1)

32. The following GHG reduction BMPs shall be implemented to the maximum extent practicable during all on-going business operations. The measures shall be incorporated into all construction contracts and operations related to the Project.

- All heavy-duty trucks entering or operated on the project site shall be model year 2014 or later, to the maximum extent practicable, and transition to zero-emission vehicles shall be expedited, with the fleet fully zero emission beginning in 2030 or when such vehicles are commercially available, whichever date is later.
- All ocean-going vessels calling at the Refinery shall use engines meeting the International Maritime Organization's Tier 4 engine standard or higher to the maximum extent practicable.
- All ocean-going vessels calling at the Refinery shall comply with CARB's At- Berth Regulation, including meeting the onboard auxiliary diesel engine operational time limits and onboard auxiliary-diesel-engine power generation reductions to the maximum extent practicable. All ocean-going vessels shall comply with the voluntary vessel speed reduction zones established by National Oceanic and Atmospheric Administration.
- All engines in articulated tug-barge combinations and tugboats assisting oceangoing vessels shall meet U.S. Environmental Protection Agency (EPA) Tier 4 engines standards, and be equipped with diesel particulate filters to the maximum extent practicable.
- All locomotives shall meet U.S. EPA Tier 4 engine standards to the maximum extent practicable.
- Utilize a "clean fleet" (e.g., zero-emission light-and medium-duty delivery trucks, vans, automobiles, railcar engines, and vessels) as part of business operations to the maximum extent practicable.

- Monitor and be in compliance with all current air quality regulations for on-road trucks including CARB's Heavy-Duty (Tractor-trailer) Greenhouse Gas Regulation, Periodic Smoke Inspection Program, and the Statewide Truck and Bus Regulation.

Demolition and Site Clean-Up/Reuse Program

33.1 The Permittee shall demolish and remove all portions of the facility that will not be used for any phase of the Project or any intended future use of the facility. Upon the permanent closure of the facility, the Permittee shall demolish and remove all remaining portions of the facility. During the operation of the Project, the Permittee shall investigate soil conditions at the site and, where necessary, clean-up and restore the site to a condition suitable for commercial and industrial land uses. To assure the performance of these requirements, the Permittee shall do all of the following:

(a) Within 30 days following final approval of the land use permit, the Permittee shall provide a Corporate Guarantee to Contra Costa County to guarantee the performance and implementation of all tasks specified in the Demolition and Site Clean-Up/Reuse Work Plan (Work Plan). The initial value of the Corporate Guarantee shall be no less than $155,000,000, based on estimated costs as described in Table A. The Corporate Guarantee shall be adjusted annually for inflation by March 15 of each year following project approval. The inflation adjustment shall be calculated using the inflation factor in Title 27, California Code of Regulations, Section 22236, for the prior calendar year. Following any adjustment to the value of the Corporate Guarantee pursuant to Condition 32.3, then the Corporate Guarantee shall be adjusted annually for inflation in accordance with this subsection, except that no inflation adjustment shall be required for a year in which the value of a Corporate Guarantee was adjusted between January 1 and March 15 based on an updated cost estimate.

(b) The following portions of the facility shall be demolished and removed as follows:

(1) The SRU Chem Plant Stack shall be demolished and removed no later than December 31, 2024.

(2) The 2 Reformer and 3 Reformer process units shall be demolished and removed no later than five years after startup of the Pretreatment Unit.

(c) Within 30 months following final approval of the land use permit, the Permittee shall submit a Work Plan as specified in Condition 32.2 for review and reasonable approval by the Contra Costa County Conservation and Development Director or designee.

33.2 The Work Plan must include all of the following information:

(a) The Work Plan must specify which portions of the facility will be demolished and removed from the site over time. The Work Plan must include a description of all above-ground and below-ground structures, equipment, and appurtenances that will be demolished and removed from the site.

(b) The Work Plan must include the following schedules. Each schedule must propose a phased completion plan demonstrating steady progress by including all interim tasks necessary to demolish and remove each portion of the facility, and the estimated time necessary to complete each task.

(1) A schedule for removal of all portions of the facility that will not be used for any phase of the Project or any intended future use of the facility. All demolition and removal activities included in this schedule must be completed no later than 20 years after approval of the Work Plan.

(2) A schedule for completing the demolition and removal of all remaining portions of the facility upon the permanent closure of the facility.

(c) The Work Plan must include a schedule for completing the investigation of soil conditions at the site. The soil investigation must be completed no later than 15 years after final approval of the land use permit.

(d) The Work Plan must include a schedule for restoring the site to a condition suitable for commercial and industrial land uses as determined by the applicable regulatory agencies having oversight of restoration activities.

(e) The Work Plan must include cost estimates for demolition and removal, and for site investigations and associated potential clean-up.

(f) At least once every five years, the Permittee shall submit an amended Work Plan for review and reasonable approval by the Contra Costa County Conservation and Development Director or designee. The amended Work Plan shall include the information specified in subsections (a) through (e) of Condition 32.2, and include the following additional information:

(1) A description of all demolition and clean-up tasks and activities completed following the submission of the prior Work Plan, and the status of in-progress Work Plan tasks and activities.

(2) An accounting of actual expenditures on all demolition and clean-up tasks and activities completed under the initial Work Plan and all amended Work Plans.

(3) A schedule of all demolition and clean-up tasks and activities that are expected to be implemented in the next five-year period.

(g) The Permittee shall comply with all applicable federal, state, and local laws and regulations when performing all demolition and clean-up tasks and activities at the site.

33.3 The Corporate Guarantee required by Condition 32.1 must comply with the following requirements.

(a) The Guarantor must be:

(1) A parent corporation of the Permittee; or

(2) An entity whose parent corporation is also the parent corporation of Permittee; or

(3) An entity that is engaged in a substantial contractual business relationship with the Permittee and issues the Corporate Guarantee as an act incident to that business relationship.

(b) The Guarantor must meet the following financial means test based on the Guarantor's audited year-end financial statements:

(1) A current rating for its most recent bond issuance of AAA, AA, A, or BBB, issued by Standard & Poor's, or Aaa, Aa, A, or Baa, issued by Moody's; and

(2) Tangible net worth at least six times the sum of the current cost estimate covered by the Corporate Guarantee; and

(3) Tangible net worth of at least $15 million; and

(4) Assets located in the United States amounting to at least 90 percent of its total assets or at least six times the sum of the current cost estimate covered by the Corporate Guarantee.

(c) The Corporate Guarantee shall be substantially in the form attached as Appendix A, subject to reasonable approval by Contra Costa County.

(d) If the Guarantor fails to meet the requirements of the financial means test under Condition 32.3 or wishes to terminate the Corporate Guarantee, the Guarantor shall send notice of the failure or intent to terminate by certified mail to Permittee and Contra Costa County within 90 days after the end of the financial reporting year in which the failure or intent to terminate occurs. The Corporate Guarantee shall terminate no less than 60 days after the date that Permittee and Contra Costa County have received notice of failure or intent to terminate, as evidenced by the return receipts. Subject to reasonable approval by Contra Costa County, the Guarantor shall establish alternate coverage on behalf of Permittee, or Permittee shall establish alternate coverage, within 60 days after the County's receipt of notice of failure or intent to terminate.

Table A – Initial Corporate Guarantee Basis

Activity	Estimated Costs ($Millions)
Net Demolition Costs for Idled Assets	**$ 70**
Net Demolition Costs for Operating Assets	**$ 35**
Estimated Site Investigation & Non-Determined Clean-up or Other Costs Held in Reserve	**$ 50**
Total	**$ 155**

(e) Within 30 days after the County's approval of the Work Plan and each amended Work Plan, the value of the Corporate Guarantee shall be updated to reflect all updated cost estimates included in the Work Plan or amended Work Plan, as applicable.

(f) Subject to reasonable approval by Contra Costa County, the value of the Corporate Guarantee may be adjusted to reflect:

(1) Completion of demolition activities that have occurred; and

(2) Completion of site investigation or other activities that have occurred as set forth in the Work Plan.

(3) Changes in estimates or defined work scope as it relates to any changes to demolition, clean-up, or site investigation activities.

(g) The portion of the Corporate Guarantee for Estimated Site Investigation & Non-Determined Clean-up or Other Costs (in Table A) shall maintain a minimum of $25 million held in reserve until site investigation activities are complete, which amount shall not be subject to adjustment for inflation.

33.4 For purposes of this condition, the following terms have the following meanings:

(a) "Facility" means all structures, processing equipment, and other equipment and appurtenances used for manufacturing, storage, or distribution at the Martínez refinery located at 150 Solano Way, Pacheco CA 94553.

(b) "Project" means the Martinez Refinery Renewable Fuels Project, County File #CDLP20-02046.

(c) "Site" means the real property where the Martinez refinery is located, at 150 Solano Way, Pacheco CA 94553.

Work Restrictions

34. The applicant shall make a good faith effort to minimize project-related disruptions to adjacent properties and to other uses on the site. This shall be communicated to project-related contractors.

35. The site shall be maintained in an orderly fashion. Following the cessation of construction activity, all construction debris shall be removed from the site.

36. Non-emergency maintenance, construction, and other activities on the site related to this use shall be prohibited on State and Federal holidays on the calendar dates that these holidays are observed by the State or Federal government as listed below:

    New Year's Day (State and Federal)
    Birthday of Martin Luther King, Jr. (State and Federal)
    Washington's Birthday (Federal)
    Lincoln's Birthday (State)
    President's Day (State)
    Cesar Chavez Day (State)
    Memorial Day (State and Federal)
    Juneteenth National Independence Holiday (Federal)
    Independence Day (State and Federal)
    Labor Day (State and Federal)
    Columbus Day (Federal)
    Veterans Day (State and Federal)
    Thanksgiving Day (State and Federal)
    Day after Thanksgiving (State)
    Christmas Day (State and Federal)

    For specific details on the actual days and dates that these holidays occur, please visit the following websites:

    Federal Holidays: www.federalreserve.gov/aboutthefed/k8.htm

    California Holidays: www.sos.ca.gov/holidays.htm

Application Processing Fees

37. The Land Use Permit application was subject to an initial deposit of $15,000 that was paid with the application submittal, plus time and material costs if the application review expenses exceed the initial deposit. Any additional fee due must be paid prior to issuance of a building

permit, or 60 days of the effective date of this permit, whichever occurs first. The fees include costs through permit issuance and final file preparation. Pursuant to Contra Costa County Board of Supervisors Resolution Number 2013/340, where a fee payment is over 60 days past due, the application shall be charged interest at a rate of ten percent (10%) from the date of approval. The applicant may obtain current costs by contacting the project planner. A bill will be mailed to the applicant shortly after permit issuance in the event that additional fees are due.

Community Outreach and Benefits

38. The applicant has agreed to enter into a Community Benefits Agreement with the County to implement the permittee's planned Community Benefit Initiative for the Project. The agreement will detail the benefit(s) that the Project will provide the community and an implementation schedule for the agreed-upon community benefits. At least 30-days prior to scheduling of a final building permit inspection for this project (e.g., occupation of the subject site), the permittee shall provide CDD staff with evidence that the permittee and County have entered into a Community Benefits Agreement.

39. In order to help support the local economy, Marathon shall encourage its employees and subcontractors to patronize local businesses and restaurants during breaks and mealtimes, and that they use personal vehicles during these break times and not construction equipment, such as dump trucks or other large construction vehicles, so as to minimize unnecessary road wear by heavy trucks on local roadways.

PUBLIC WORKS
CONDITIONS OF APPROVAL FOR LAND USE PERMIT CDLP20-02046

Applicant shall comply with the requirements of Title 8, Title 9 and Title 10 of the Ordinance Code. Any exceptions must be stipulated in these Conditions of Approval. Conditions of Approval are based on the site plan submitted to the Department of Conservation and Development on October 2, 2020.

COMPLY WITH THE FOLLOWING CONDITIONS OF APPROVAL PRIOR TO INITIATION OF THE USE PROPOSED UNDER THIS PERMIT.

General Requirements:

40. Improvement plans prepared by a registered civil engineer shall be submitted, if necessary, to the Public Works Department, Engineering Services Division, along with review and inspection fees, and security for all improvements required by the Ordinance Code for the conditions of approval of this permit. Any necessary traffic signing and striping shall be included in the improvement plans for review by the Transportation Engineering Division of the Public Works Department.

Roadway Improvements (Frontage/Off-Site):

41. Any cracked and displaced curb, gutter, and sidewalk shall be removed and replaced along the project frontage of Waterfront Road, Imhoff Drive, Arnold Industrial Way, and Solano Avenue. Concrete shall be saw cut prior to removal. Existing lines and grade shall be maintained. New curb and gutter shall be doweled into existing improvements.

42. Applicant shall submit a Traffic Management Plan for review and approval by the Contra Costa County Public Works Department, City of Martinez, and City of Concord prior to initiation of construction operations associated with this project. At a minimum the following shall be included:

    - The Traffic Management Plan shall be prepared in accordance with the most current California Manual on Uniform Traffic Control Devices, and will be subject to periodic review by the Contra Costa County Public Works Department, City of Martinez and City of Concord throughout the life of all construction and demolition phases.
    - Truck drivers shall be notified of and required to use the most direct route between the site and the freeway;
    - All site ingress and egress shall occur only at the main driveways to the Project site;
    - Construction vehicles shall be monitored and controlled by flaggers;
    - If during periodic review the Contra Costa County Public Works Department determines the Traffic Management Plan requires modification, applicant shall revise the Traffic Management Plan to meet the specifications of the Contra Costa County Public Works Department to address any identified issues. This may include such actions as traffic signal modifications, staggered work hours, or other measures deemed appropriate by the Public Works Department.
    - If required, applicant shall obtain the appropriate permits from Caltrans City of Concord. City of Martinez, and the Contra Costa County Public Works Department for the movement of oversized or excessive load vehicles on state-administered highways, City, or County maintained roads respectively.

Access to Adjoining Property:

<u>Encroachment Permit</u>

43. Applicant shall obtain an encroachment permit from the Public Works Department, if necessary, for Traffic Control and signal optimization within the right-of-way of Imhoff Drive and Waterfront Road.

44. Applicant shall obtain an encroachment permit from Caltrans for Traffic Control and signal optimization within the State right-of-way.

45. Applicant shall obtain an encroachment permit from the City of Concord for Traffic Control and signal optimization within City right-of-way.

Construction:

46. Prior to the start of construction-related activities, the applicant shall prepare a Traffic Control Plan (TCP), including a haul route, for the review and approval of the Public Works Department.

47. Applicant shall survey the pavement condition on Imhoff Drive and Waterfront Road prior to the commencement of any work on site, with Public Works Department approval. The survey shall include a photo/video of the roadways. Applicant shall complete any remedial work prior to initiation of use; OR, provide a bonded agreement assuring completion of the remedial work.

48. Applicant shall provide a pavement analysis for those roads along the proposed haul route or any alternate route(s) that are proposed to be utilized by the hauling operation. This study shall analyze the existing pavement conditions, and determine what impact the hauling operation will have over the life of the project. The study shall provide recommendations to mitigate identified impacts.

ADVISORY NOTES

THE FOLLOWING INFORMATION DOES NOT CONSTITUTE CONDITIONS OF APPROVAL. IT IS PROVIDED TO ALERT THE APPLICANT TO LEGAL REQUIREMENTS OF THE COUNTY AND OTHER PUBLIC AGENCIES TO WHICH THIS PROJECT MAY BE SUBJECT.

A. **NOTICE OF NINETY (90) DAY OPPORTUNITY TO PROTEST FEES, DEDICATIONS, RESERVATIONS, OR OTHER EXACTIONS PERTAINING TO THE APPROVAL OF THIS PERMIT.**

This notice is intended to advise the applicant pursuant to Government Code Section 66000, et seq., the applicant has the opportunity to protest fees, dedications, reservations, and/or exactions required as part of this project approval. The opportunity to protest is limited to a ninety (90) day period after the project is approved.

The ninety (90) day period in which you may protest the amount of any fee or the imposition of any dedication, reservation, or other exaction required by this approved permit, begins on the date this permit was approved. To be valid, a protest must be in writing pursuant to Government Code Section 66020 and delivered to the Community Development Division within ninety (90) days of the approval date of this permit.

B. Prior to applying for a building permit, the applicant may wish to contact the following agencies to determine if additional requirements and/or additional permits are required as part of the proposed project:

- County Building Inspection Division
- County Health Services Dept., Environmental Health Division
- Contra Costa Consolidated Fire Protection District
- California Department of Fish and Wildlife
- United States Department of Fish and Wildlife
- Bay Area Air Quality Management District

C. The applicant will need to comply with the requirements of the Bridge/Thoroughfare Fee Ordinance for the Central County Area of Benefit as adopted by the Board of Supervisors prior to issuance of a building permit.

D. This project may be subject to the requirements of the Department of Fish and Wildlife. It is the applicant's responsibility to notify the Department of Fish and Wildlife of any proposed construction within this development that may affect any fish and wildlife resources, per the Fish and Game Code.

APPENDIX A

GUARANTEE

Shall be on guarantor's letterhead stationery. It shall also contain original signature of Guarantor

[TITLE]
[AGENCY]
[ADDRESS]

Guarantee made this ______Date________ by __________Name of Guaranteeing Entity_______________, a business entity organized under the laws of ___________Insert Name of State_______________, herein referred to as Guarantor, to the [AGENCY (Contra Costa County)] obligee on behalf of ______Applicant of ____Business Address____.

Recitals

1. Guarantor meets or exceeds the financial means test criteria for guarantors, which means that Guarantor shall have:
   a. A current rating for its most recent bond issuance of AAA, AA, A, or BBB issued by Standard and Poor's or Aaa, Aa, A or Baa as issued by Moody's; and
   b. Tangible net worth each at least six times the amount of the current cost estimate to be demonstrated by the test; and
   c. Tangible net worth of at least $15 million; and
   d. Assets located in the United States amounting to at least 90 percent of its total assets or at least six times the amount of the current cost estimate to be demonstrated by the test.

2. Guarantor is a parent corporation of the _________________Applicant_____________ ; ☐ is a firm whose parent corporation, _______________Corporate Parent__________________________ , is also the parent corporation of Operator__________________________; or ☐ engages in a substantial business relationship with __________________Applicant and is issuing this guarantee as an act incident to that business relationship.

3. _______________Applicant_____________________ has developed a Demolition and Site Clean-up Work Plan as required by the [SPECIFY LAND USE PERMIT].

4. [Insert appropriate phrase: "On behalf of our subsidiary" (if guarantor is a parent corporation of the Applicant); "On behalf of our affiliate" (if guarantor is a firm whose parent corporation is also the parent corporation of the Applicant); or "Incident to our business relationship with" (if guarantor is providing guarantee as an incident to a substantial business relationship with the Applicant)] ______________Applicant____________ . Guarantor guarantees to Contra Costa County that in the event that _____________Applicant____________ fails to perform activities identified in the Demolition and Site Clean-up Work Plan whenever required to do so, Guarantor shall do so.

5. Guarantor agrees that if at any time during or at the end of any fiscal year before termination of this guarantee the Guarantor fails to meet the financial means test criteria, Guarantor shall send within 90 days, by either registered or certified mail, notice to Contra Costa County, and the __________Applicant___________, of such failure and that he or she intends to provide alternate financial assurance, including without limitation surety bond, letter of credit, insurance or trust fund, as applicable, in the name of ___________Applicant____________ if the __________Applicant___________fails to obtain such assurance. Within 120 days after the end of such fiscal year or other occurrence, Guarantor shall establish such alternate financial assurance in the name of __________Applicant___________ in the amount of the applicable current cost estimate, unless __________Applicant has done so.

6. Guarantor agrees to notify Contra Costa County, and the __________Applicant__________, by either registered or certified mail of a voluntary or involuntary proceeding under the Bankruptcy Code, 11 U.S.C. Sections 101-1330, naming Guarantor as debtor within ten days after commencement of the proceeding.

7. Guarantor agrees to remain bound under this guarantee notwithstanding amendment or modification of the Demolition and Site Clean-up Work Plan.

8. Guarantor agrees to remain bound under this guarantee for so long as __________Applicant___________ must comply with the applicable financial assurance requirements in the Land Use Permit, except that Guarantor may cancel this guarantee by sending notice by registered or certified mail to Contra Costa County, and the ______Applicant_________. Such cancellation shall become effective no earlier than 120 days after receipt of such notice by Contra Costa County, and the _____________Applicant___, as evidenced by the return receipts.

11. Guarantor agrees that if ______________Applicant_________________ fails to provide alternate financial assurance, including without limitation surety bond, letter of credit, insurance or trust fund, as applicable, within 90 days after a notice of cancellation by Guarantor is received from Guarantor by Contra Costa County, and the ___________Applicant__________, Guarantor shall provide such alternate financial assurance in the name of ______________Applicant__________________ in the amount of the applicable current cost estimate.

12. Guarantor expressly waives notice of acceptance of this guarantee by Contra Costa County, or the Applicant ________. Guarantor also expressly waives notice of amendments or modifications of the Demolition and Site Clean-up Work Plan.

The parties below certify that this document is being executed in accordance with the requirements of the Contra Costa County land use permit.

Effective date: ____

____
Name of Guarantor

____
Authorized Signature of Guarantor

➢

____
Typed or Printed Name of Person Signing

____
Title and Phone Number of Person Signing

➢

____
Signature of Witness or Notary and Seal

Privacy Statement

The Information Practices Act (California Civil Code Section 1798.17) and the Federal Privacy Act (5 U.S.C. 552a(e)(3)) require that this notice be provided when collecting personal information from individuals.

AGENCY REQUESTING INFORMATION: California Department of Resources Recycling and Recovery (CalRecycle).

UNIT RESPONSIBLE FOR MAINTENANCE OF FORM: Financial Assurances Section, California Department of Resources Recycling and Recovery (CalRecycle), 1001 I Street, P.O. Box 4025, Sacramento, California 95812-4025. Contact the Manager, Financial Assurances Section, at (916) 341-6000.

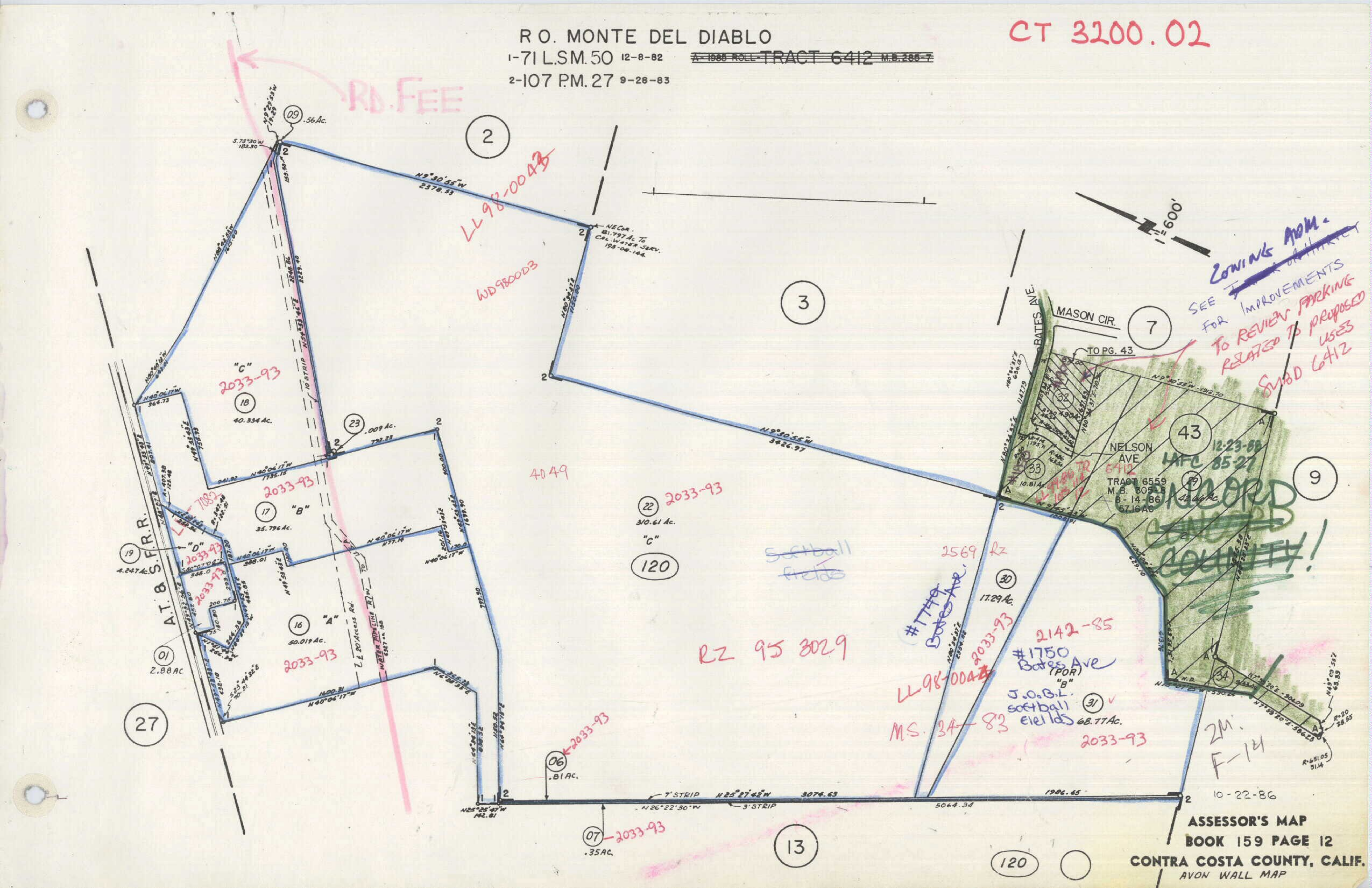
AUTHORITY: Public Resources Code section 43600 et seq.

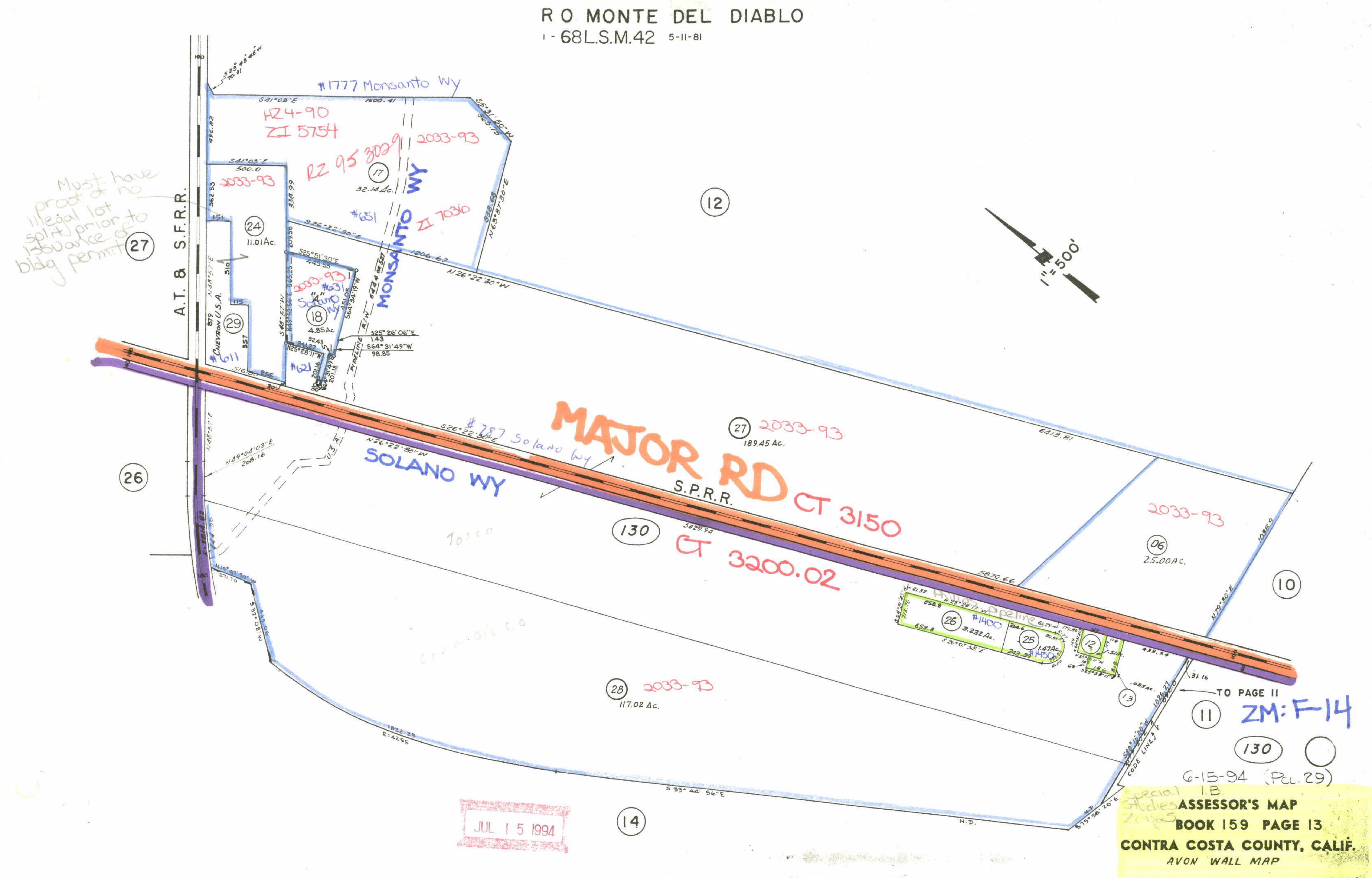
PURPOSE: The information provided will be used to verify adequate financial assurance of solid waste disposal facilities listed.

REQUIREMENT: Completion of this form is mandatory. The consequence of not completing this form is denial or revocation of a permit to operate a solid waste disposal facility.

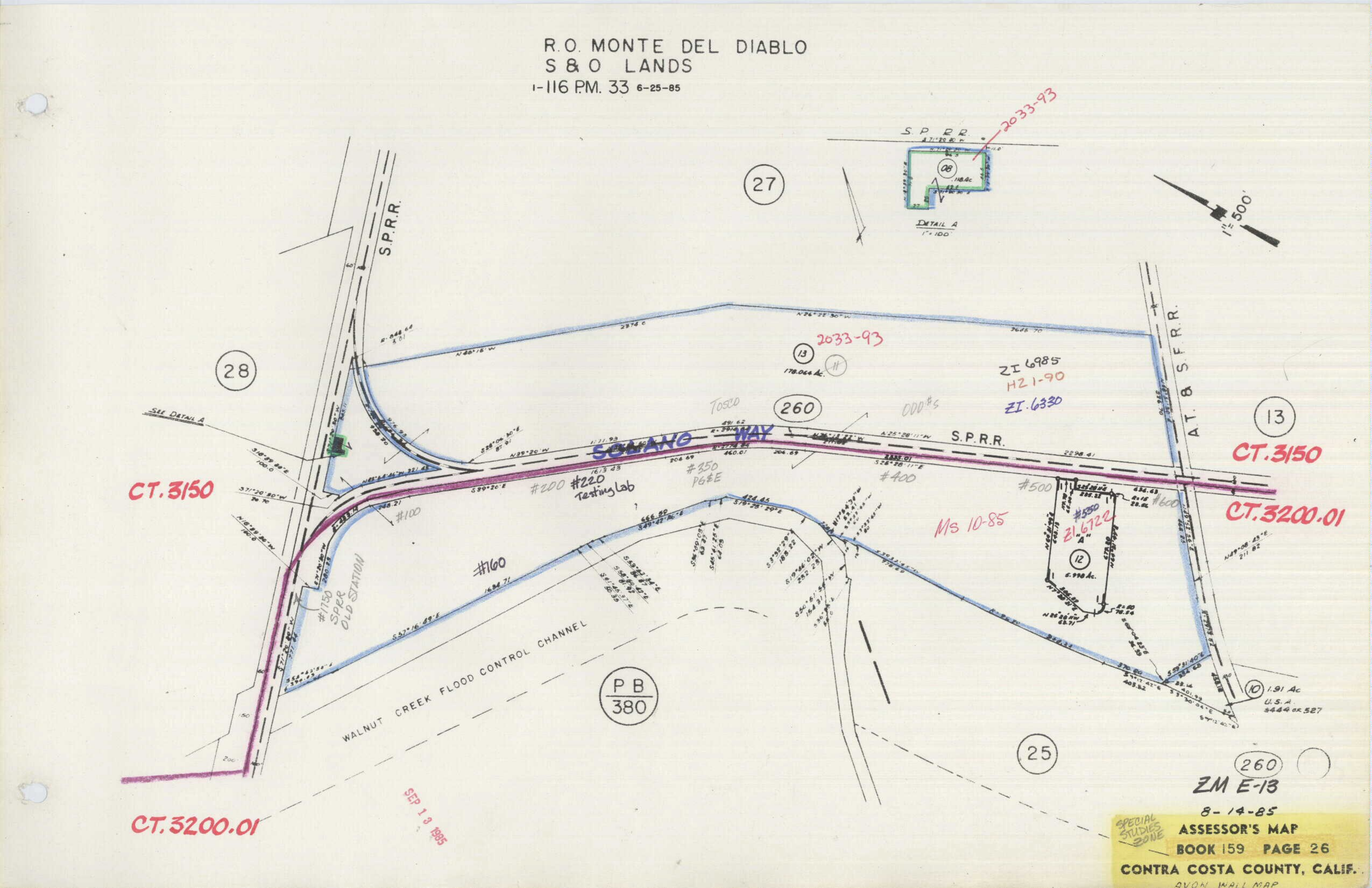
OTHER INFORMATION: After review of this document, you may be requested to provide additional information regarding the acceptability of this mechanism.

ACCESS: Information provided in this form may be provided to the U.S. Environmental Protection Agency, State Attorney General, Air Resources Board, California Department of Toxic Substances Control, Energy Resources Conservation and Development Commission, Water Resources Control Board, and California Regional Water Quality Control Boards. For more information or access to your records, contact the California Department of Resources Recycling and Recovery (CalRecycle) , 1001 I Street, P.O. Box 4025, Sacramento, California 95812-4025, (916) 341-6000.


CT 3200.02
R O. MONTE DEL DIABLO
1-71 L.S.M. 50 12-8-82
2-107 P.M. 27 9-28-83
~~A-1988 ROLL TRACT 6412 M.B. 288-7~~
RD. FEE
2
3
7
9
13
27
43
120
N 9°30'55" W 2378.53
N 9°30'55" W 3426.97
NE Cor. 81.797 Ac To Col. Water Serv.
LL 98-0043
WD 980003
"C"
2033-93
18
40.334 Ac.
23
.009 Ac.
09
.56 Ac.
"B"
17
35.796 Ac.
"D"
19
4.247 Ac.
"A"
16
50.019 Ac.
01
2.88 AC
10' STRIP
Water Pipeline R/W
A.T. & S.F. R.R.
4049
22
310.61 Ac.
120
~~Softball fields~~
RZ 95 3029
2569 RZ
30
17.29 Ac.
#1740 Bates Ave.
2142-85
#1750 Bates Ave
(POR) "B"
J.O.B.L. softball fields
31
68.77 Ac.
LL-98-0043
M.S. 34-83
06
.81 Ac.
07
.35 AC.
7' STRIP
3' STRIP
N 25°27'42" W 3074.63
5064.34
1986.65
N 26°22'30" W
BATES AVE.
MASON CIR.
TO PG. 43
NELSON AVE
TRACT 6559 M.B. 305-3 8-14-86 67.16 AC
LAFC 85-27
12-23-88
CONCORD
~~CONCORD COUNTY!~~
32
33
34
10.81 Ac.
SEE ZONING ADM. FOR IMPROVEMENTS
TO REVIEW PARKING RELATED TO PROPOSED USES SUBD 6412
1" = 600'
ZM. F-14
10-22-86
ASSESSOR'S MAP
BOOK 159 PAGE 12
CONTRA COSTA COUNTY, CALIF.
AVON WALL MAP



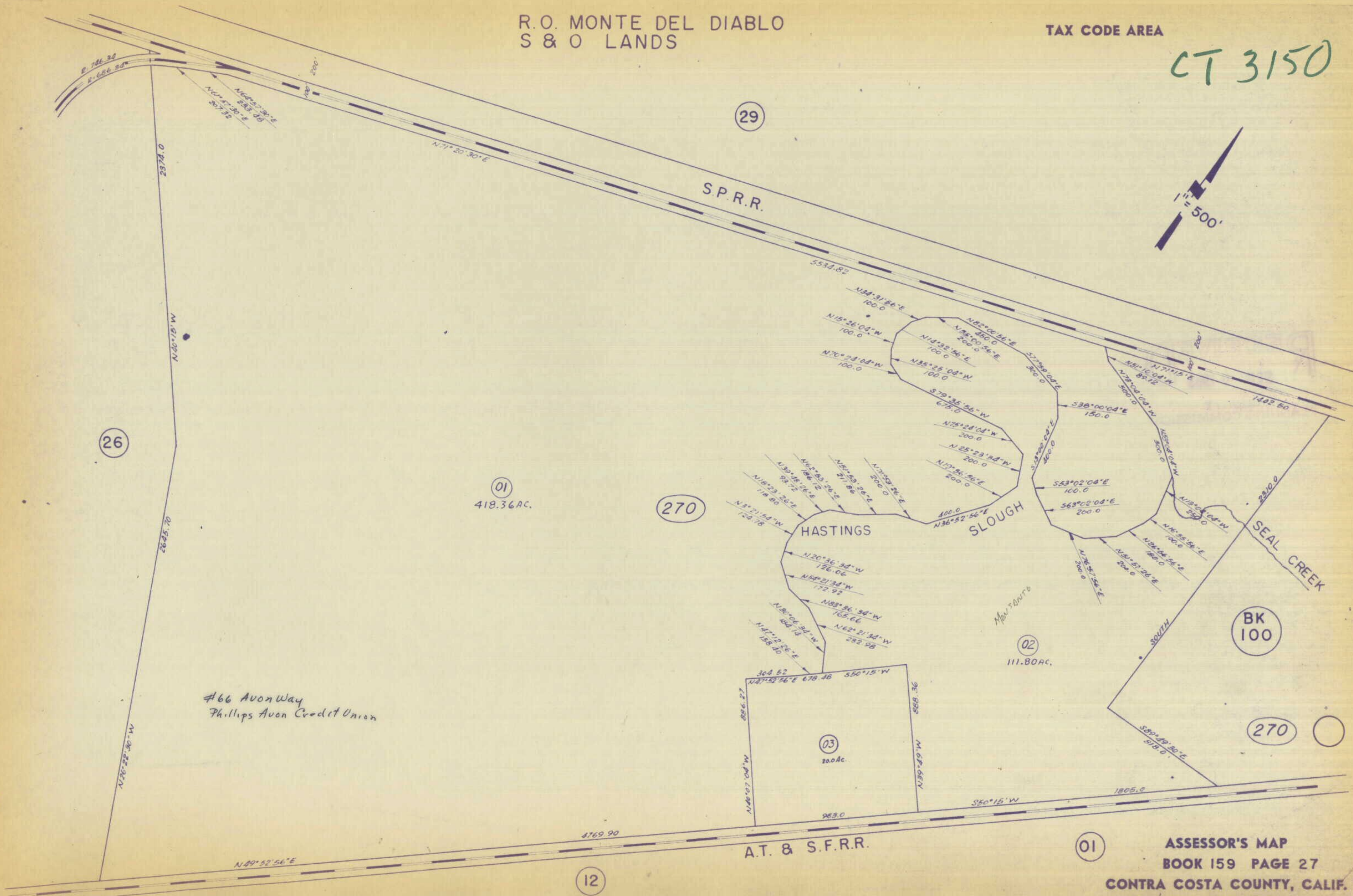
R O MONTE DEL DIABLO
1 - 68 L.S.M. 42 5-11-81
#1777 Monsanto Wy
HZ4-90
ZI 5754
RZ 95 3029
2033-93
MONSANTO WY
ZI 7036
Must have proof of no illegal lot split prior to issuance of bldg permit
A.T. & S.F.R.R.
CHEVRON U.S.A.
PIPELINE R/W
MAJOR RD
S.P.R.R.
SOLANO WY
#787 Solano Wy
CT 3150
CT 3200.02
1" = 500'
TO PAGE 11
ZM: F-14
6-15-94 (Pcl. 29)
JUL 15 1994
Special Studies Zones
ASSESSOR'S MAP
BOOK 159 PAGE 13
CONTRA COSTA COUNTY, CALIF.
AVON WALL MAP


R.O. MONTE DEL DIABLO
S & O LANDS
1-116 P.M. 33 6-25-85
S.P.R.R.
2033-93
DETAIL A
1" = 100'
27
1" = 500'
28
13
178.064 Ac.
ZI 6985
HZ1-90
ZI.6330
Tosco
260
SOLANO WAY
S.P.R.R.
AT. & S.F.R.R.
SEE DETAIL A
CT. 3150
CT. 3150
CT. 3200.01
#200 #220
Testing Lab
#350
PG&E
#400
#500
#550
ZI 6722
#600
#100
#160
Ms 10-85
"A"
12
5.998 Ac.
#1750
SPRR
OLD STATION
WALNUT CREEK FLOOD CONTROL CHANNEL
PB
380
25
10
1.91 Ac
U.S.A.
8444 OR 527
260
ZM E-13
8-14-85
CT. 3200.01
SEP 13 1985
SPECIAL STUDIES ZONE
ASSESSOR'S MAP
BOOK 159 PAGE 26
CONTRA COSTA COUNTY, CALIF.
AVON WALL MAP

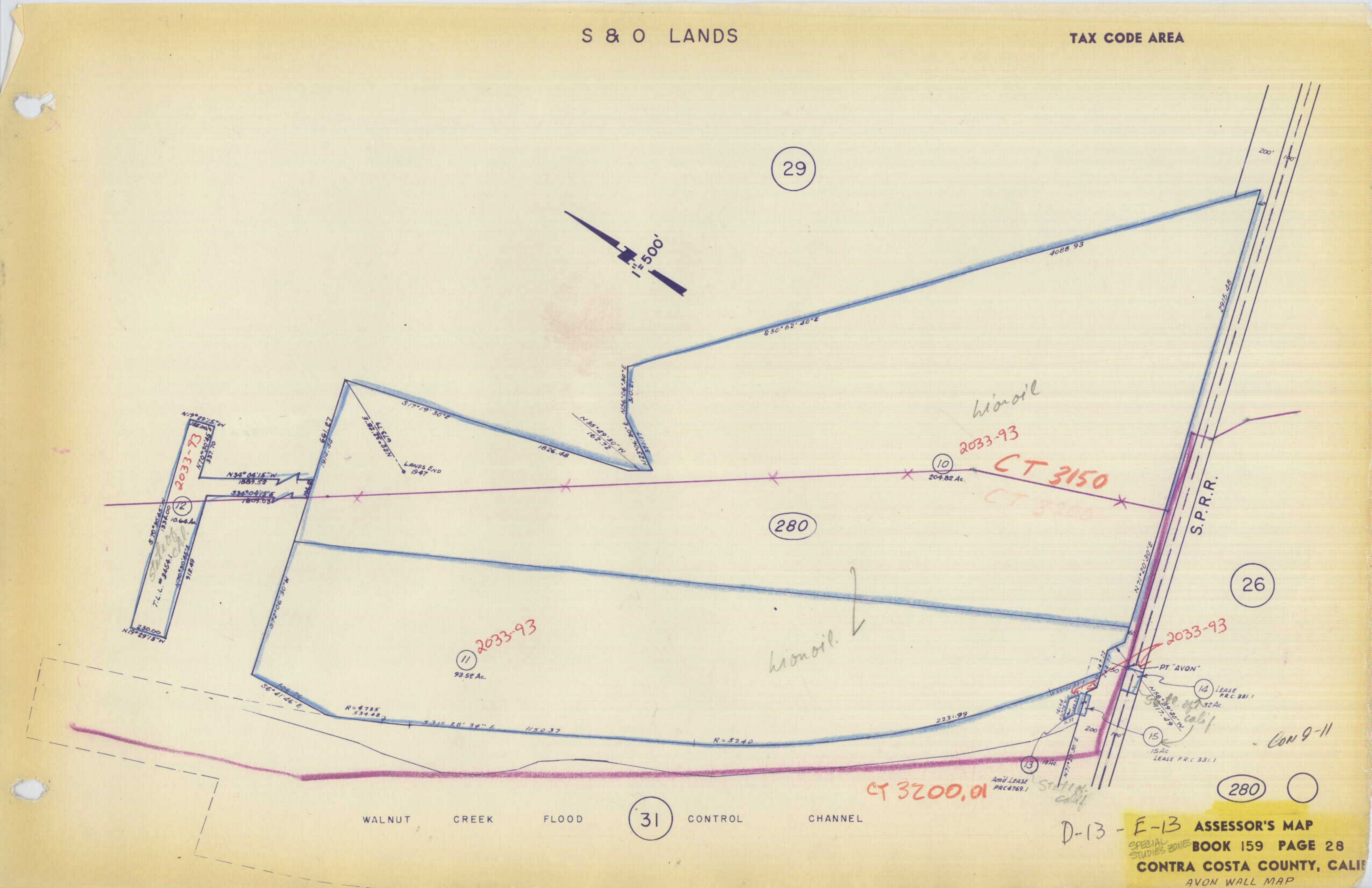
R.O. MONTE DEL DIABLO
S & O LANDS

TAX CODE AREA

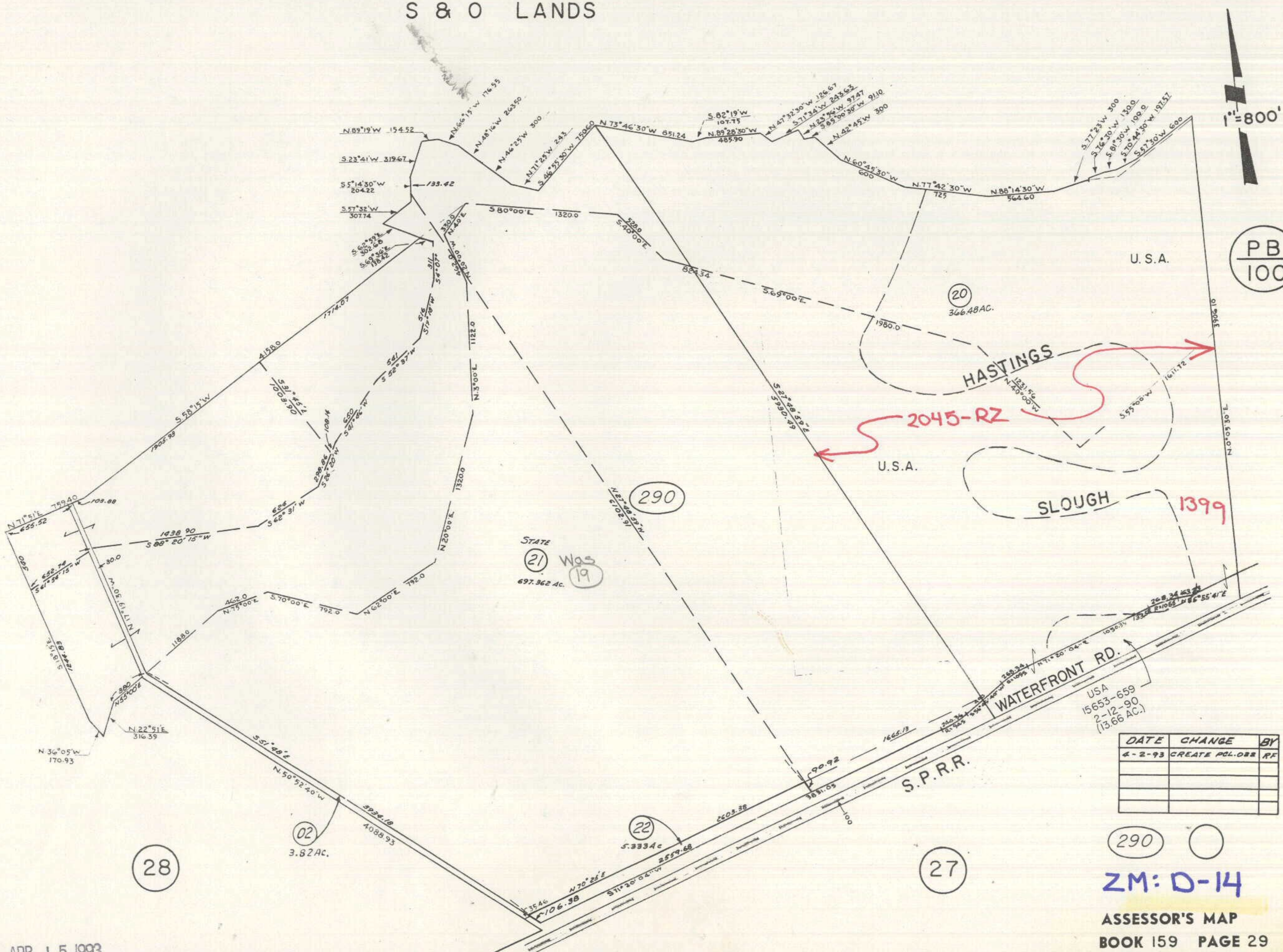
CT 3150



ASSESSOR'S MAP
BOOK 159 PAGE 27
CONTRA COSTA COUNTY, CALIF.



S & O LANDS
TAX CODE AREA
29
1" = 500'
4088.93
S 50°52'40" E
2915.48
200'
100'
Lion oil
2033-93
10
204.82 Ac.
CT 3150
CT 3200
S.P.R.R.
280
26
N 71°20'30" E
S 17°19'30" E
1826.48
N 35°49'30" W
163.72
LANDS END
1947
N 34°04'15" W
1889.53
S 34°04'15" E
1809.03
2033-93
12
10.64 Ac.
State of Cal.
T.L.L. # 3454.1
230.00
N 19°29'15" W
S 72°06'30" W
2033-93
11
93.52 Ac.
Lion oil.
S 6°41'46" E
R = 4735
534.48
1150.37
R = 5240
2231.99
2033-93
PT. "AVON"
14
LEASE
P.R.C. 331.1
32 Ac
State of Calif
15
15 Ac
LEASE P.R.C. 331.1
200
100
13
18 Ac.
Am'd LEASE
PRC 4769.1
State of Calif
CT 3200.01
Con 9-11
280
WALNUT CREEK FLOOD
31
CONTROL CHANNEL
D-13 - E-13
SPECIAL STUDIES ZONES
ASSESSOR'S MAP
BOOK 159 PAGE 28
CONTRA COSTA COUNTY, CALIF
AVON WALL MAP



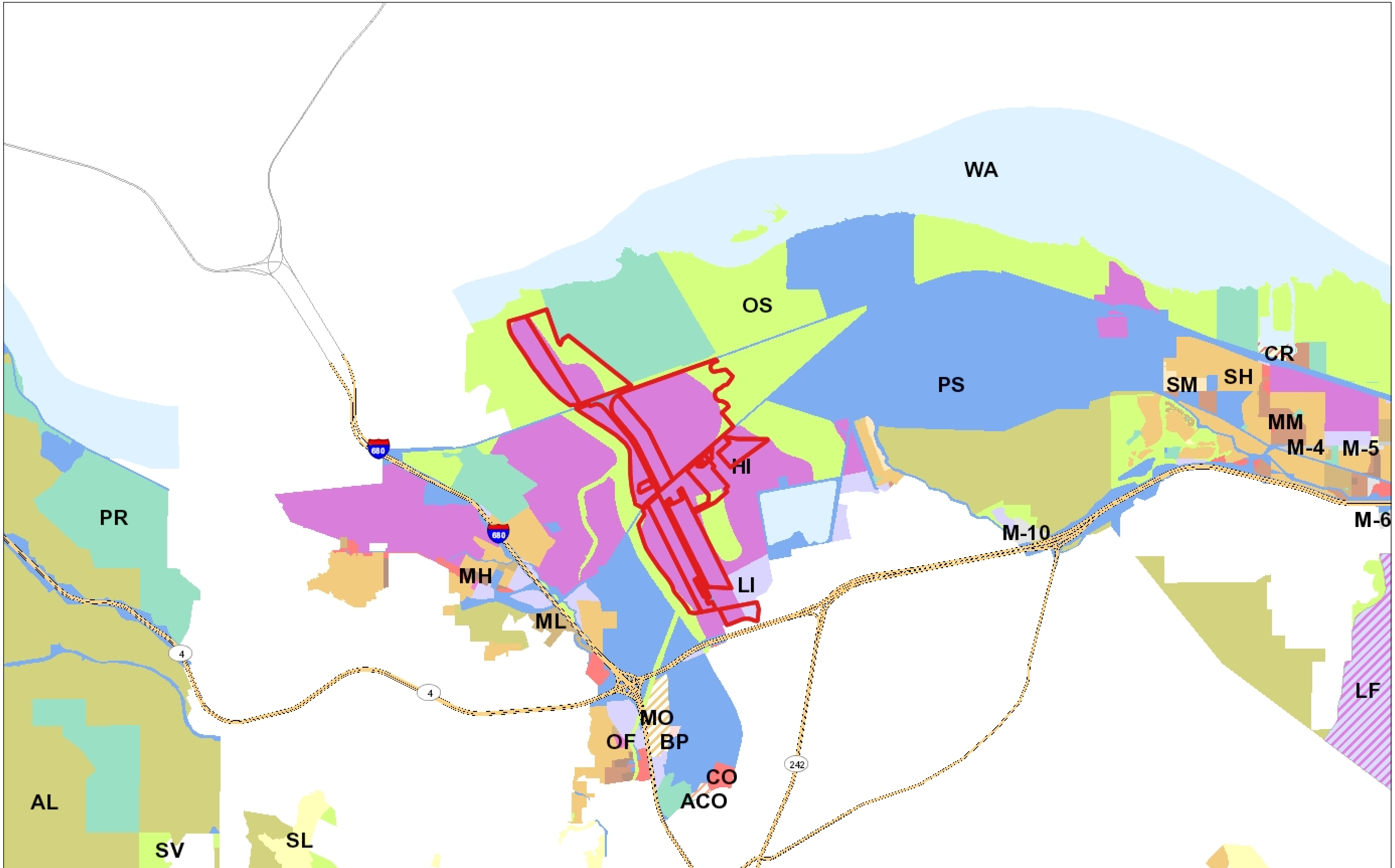
DATE	CHANGE	BY
4-2-93	CREATE PCL.022	RF

ZM: D-14

ASSESSOR'S MAP
BOOK 159 PAGE 29
CONTRA COSTA COUNTY, CALIF.
AVON WALL MAP

APR 15 1993

General Plan: HI, LI, OS



Legend

- Highways
- Highways Bay Area
- General Plan
  - SV (Single Family Residential - Ver
  - SL (Single Family Residential - Low
  - SM (Single Family Residential - Me
  - SH (Single Family Residential - Hig
  - ML (Multiple Family Residential - Lo
  - MM (Multiple Family Residential - M
  - MH (Multiple Family Residential - H
  - MV (Multiple Family Residential - V
  - MS (Multiple Family Residential - V
  - CC (Congregate Care/Senior Housi
  - MO (Mobile Home)
  - M-1 (Parker Avenue Mixed Use)
  - M-2 (Downtown/Waterfront Rodeo I
  - M-3 (Pleasant Hill BART Mixed Use
  - M-4 (Willow Pass Road Mixed Use)
  - M-5 (Willow Pass Road Commercia
  - M-6 (Bay Point Residential Mixed U
  - M-7 (Pittsburg/Bay Point BART Sta
  - M-8 (Dougherty Valley Village Cent
  - M-9 (Montalvin Manor Mixed Use)
  - M-10 (Willow Pass Business Park M
  - M-11 (Appian Way Mixed Use)
  - M-12 (Triangle Area Mixed Use)
  - M-13 (San Pablo Dam Road Mixed
  - M-14 (Heritage Mixed Use)
  - CO (Commercial)
  - OF (Office)
  - BP (Business Park)
  - LI (Light Industry)
  - HI (Heavy Industry)
  - AL, OIBA (Agricultural Lands & Off
  - CR (Commercial Recreation)
  - ACO (Airport Commercial)
  - LF (Landfill)
  - PS (Public/Semi-Public)
  - PR (Parks and Recreation)

1: 72,224

2.3 0 1.14 2.3 Miles

WGS_1984_Web_Mercator_Auxiliary_Sphere

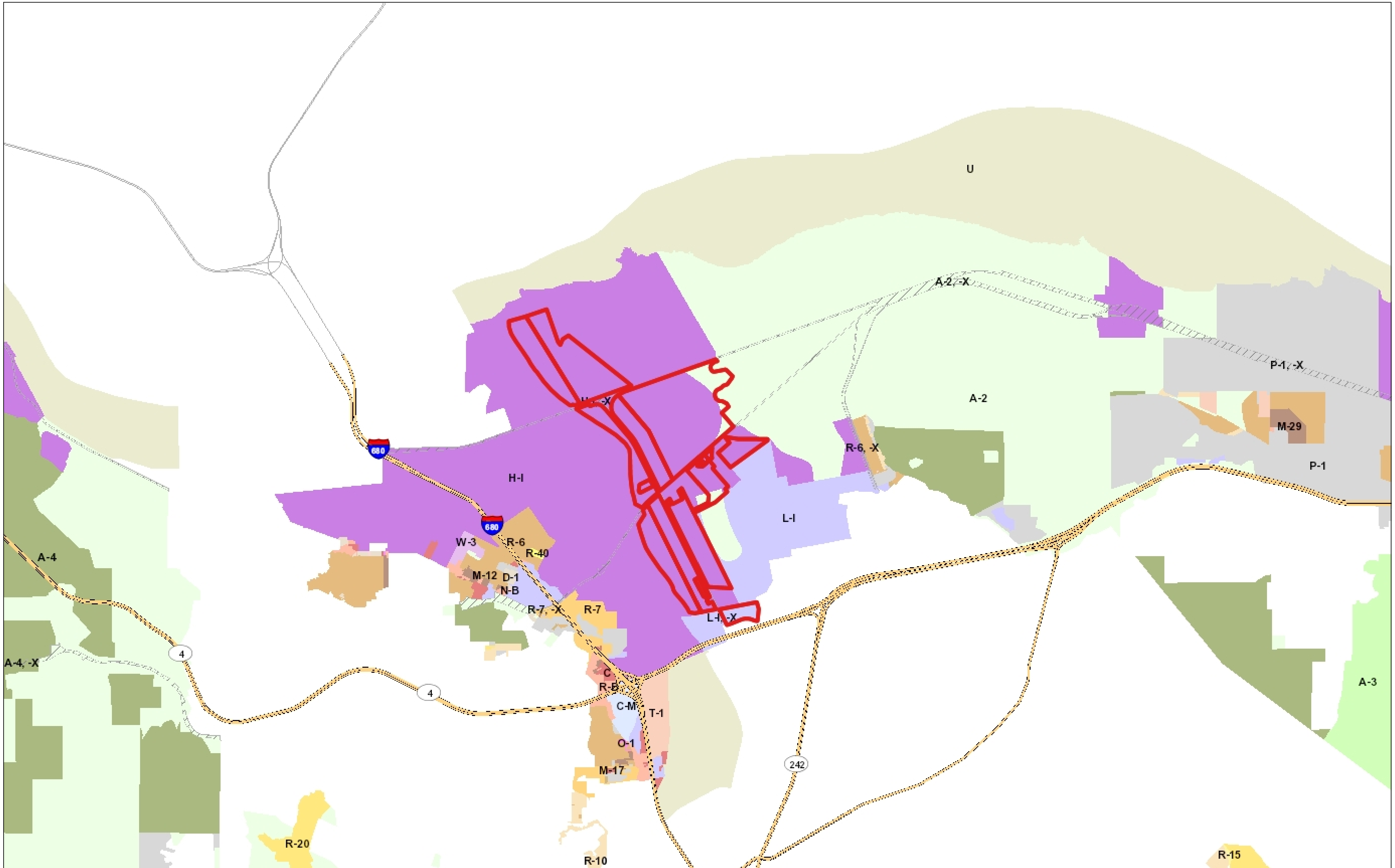
This map is a user generated static output from an Internet mapping site and is for reference only. Data layers that appear on this map may or may not be accurate, current, or otherwise reliable.

THIS MAP IS NOT TO BE USED FOR NAVIGATION

Notes

Contra Costa County -DOIT GIS

Zoning: H-I



Legend

- Highways
- Highways Bay Area

Zoning

- R-6 (Single Family Residential)
- R-6 -FH (Single Family Residential Combining District)
- R-6, -FH -UE (Single Family Resid Urban Farm Animal Exclusion Com
- R-6 -SD-1 (Single Family Resident Hillside Development Combining Di
- R-6 -TOV -K (Single Family Reside View Ordinance and Kensington Cc
- R-6, -UE (Single Family Residential Exclusion Combining District)
- R-6 -X (Single Family Residential - Combining District)
- R-7 (Single Family Residential)
- R-7 -X (Single Family Residential - Combining District)
- R-10 (Single Family Residential)
- R-10, -UE (Single Family Residenti Exclusion Combining District)
- R-12 (Single Family Residential)
- R-15 (Single Family Residential)
- R-20 (Single Family Residential)
- R-20, -UE (Single Family Residenti Exclusion Combining District)
- R-40 (Single Family Residential)
- R-40 -FH (Single Family Residenti Combining District)
- R-40, -FH -UE (Single Family Resic Urban Farm Animal Exclusion Com
- R-40, -UE (Single Family Residenti Exclusion Combining District)
- R-65 (Single Family Residential)
- R-100 (Single Family Residential)
- D-1 (Two Family Residential)
- D-1 -T (Two Family Residential - Tr District)
- D-1, -UE (Planned Unit - Urban Far Combining District)
- M-12 (Multiple Family Residential)
- M-12 -FH (Multiple Family Resident Combining District)
- M-17 (Multiple Family Residential)
- M-29 (Multiple Family Residential)
- F-R (Forestry Recreational)
- F-R -FH (Forestry Recreational - Fl District)

1: 72,224

2.3 0 1.14 2.3 Miles

WGS_1984_Web_Mercator_Auxiliary_Sphere

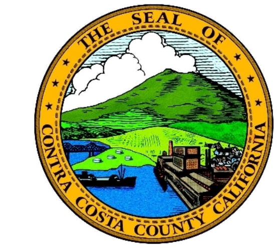
This map is a user generated static output from an Internet mapping site and is for reference only. Data layers that appear on this map may or may not be accurate, current, or otherwise reliable.

THIS MAP IS NOT TO BE USED FOR NAVIGATION

Notes

Contra Costa County -DOIT GIS

Aerial



Legend

Highways

Highways Bay Area

World Imagery

Low Resolution 15m Imagery

High Resolution 60cm Imagery

High Resolution 30cm Imagery

Citations

1: 72,224

2.3 0 1.14 2.3 Miles

WGS_1984_Web_Mercator_Auxiliary_Sphere

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THIS MAP IS NOT TO BE USED FOR NAVIGATION

Notes

Contra Costa County -DOIT GIS

COMMUNITY BENEFITS AGREEMENT

between

CONTRA COSTA COUNTY and

TESORO REFINING & MARKETING COMPANY LLC

County File CDLP#20-02046

This Community Benefits Agreement ("Agreement") is entered into as of _____________, 2022 ("Effective Date") by and between Contra Costa County ("County"), a political subdivision of the State of California, and Tesoro Refining & Marketing Company LLC ("Tesoro"), a Delaware limited liability company.

RECITALS

A. On_________, 2022, the County Planning Commission certified the environmental impact report (the "EIR") and issued to Tesoro a land use permit (the "LUP") for Tesoro's Martinez Renewable Fuels Project (the "Project"), located at Tesoro's existing Martinez Refinery (the "Refinery") in the unincorporated community of Pacheco, Contra Costa County (County File No. CDLP20-02046). The Project will repurpose the Refinery for the production of fuels from renewable sources rather than from crude oil.

B. In addition to obtaining the LUP and other discretionary state and local approvals to construct and operate the Project, including a final Authority to Construct from the Bay Area Air Quality Management District (the "BAAQMD Air Permit"), Tesoro intends to obtain one or more County building permits to construct improvements at the Refinery necessary for the Project.

C. The proposed Project is a unique land use with unique impacts on the community. The LUP contains Condition of Approval No. __, which provides that Contra Costa County and Tesoro will enter into a Community Benefits Agreement providing for certain payments to Contra Costa County upon certain conditions being satisfied relating to the Project.

AGREEMENT

NOW THEREFORE, Contra Costa County and Tesoro agree as follows:

1. Purpose. The purpose of this Agreement is to memorialize Tesoro's commitment to making an annual community benefits payment to the County and participating in a local workforce training and development program during the term of this Agreement.

2. Term. The term ("Term") of this Agreement begins on the Effective Date, and it expires upon the earliest of any of the following to occur: (a) the payment of the final community

benefit payment provided for in Section 3; (b) the revocation of the LUP; or (c) the effective date of any court decision that invalidates or sets aside the Project, the LUP, the EIR, or the BAAQMD Air Permit.

3. Community Benefits Payments.

a. Tesoro shall pay $1,000,000 to the County (the "First Payment") following the County's final approval of the LUP, the Bay Area Air Quality Management District's final approval of the BAAQMD Air Permit, or the County's issuance of the first building permit authorizing construction of improvements at the Refinery necessary for the Project, whichever occurs last. "Final Approval" means that the LUP, the BAAQMD Air Permit, and the first building permit have all been issued. The First Payment shall be made to the County on or before December 31 in the calendar year in which Final Approval occurred.

b. After payment of the First Payment, Tesoro shall pay $1,000,000 to the County in each of the nine following years (each a "Subsequent Payment"). Each of these nine Subsequent Payments shall be made to the County on or before December 31 in the year in which a Subsequent Payment is due.

c. Beginning on January 1, 2023, and on each January 1 thereafter, the payment amounts provided for in this Section 3, including the First Payment and each Subsequent Payment, shall increase based on any increase in the Consumer Price Index for the San Francisco-Oakland-Hayward Combined Statistical Area (U.S. Bureau of Labor Statistics) for the 12-month period ending on the October 31 immediately preceding the January 1 when the increase takes effect.

4. Use of Payments. The County shall, in its sole discretion, allocate funds received pursuant to this Agreement to projects and programs that benefit the communities near the Refinery by improving the health, well-being, and quality of life of residents, and that support building and sustaining a strong and resilient local economy and workforce, including the development and implementation of workforce development and training programs to prepare residents for new renewable and clean energy career pathways and jobs.

5. Other Community Benefits. In addition to the payments made by Tesoro under Section 3, and in partnership with the County, Tesoro commits to actively participate with other appropriate stakeholders in planning and designing a Workforce Training Program (the "Program") for local community members related to renewable and clean energy employment opportunities. Notwithstanding Tesoro's active participation, the County will facilitate and lead the process of Program development. This Program will focus on the development of programs and curricula, and may build on existing efforts including but not limited to job training programs provided by employers and community-based organizations, community college programs, career readiness programs at local high schools, apprenticeship programs sponsored by labor organizations, programs of the Workforce Development Board, work experience and placement services, and other workforce development initiatives within Contra Costa County. Tesoro commits to

continue its ongoing investments in training and education to support the Program and its outcomes.

6. Notices. All payments, notices, demands, and other communications made under this Agreement shall be in writing and personally delivered, sent by overnight carrier with delivery charges prepaid for next business day delivery, or sent by First Class U.S. Mail with postage prepaid, and addressed as follows:

To County:	Director of Conservation and Development 30 Muir Road Martinez, CA 94553
To Tesoro:	Tesoro Refining & Marketing Company LLC 539 South Main Street Findlay, Ohio 45840 Attention: Manager, Title & Contract Email: TCNotifications@marathonpetroleum.com
With copies to:	Tesoro Refining & Marking Company LLC 539 South Main Street Findlay, Ohio 45840 Attention: General Counsel

A payment, notice, demand, or other communication shall be deemed given on the same day it is personally delivered, on the next business day following deposit with and overnight carrier, or on the fifth day after deposit in the U.S. Mail. A party may change its address for delivery of notices under this Agreement by providing written notice of the change in accordance with this section.

7. Assignment. Tesoro's obligations under this Agreement shall be binding upon Tesoro's successors and assigns. Tesoro shall not assign this Agreement, or any of its obligations under this Agreement, to any other person or entity without the advance written approval of the County, which shall be within its sole discretion to provide. If Tesoro sells, conveys, or otherwise transfers ownership of the Refinery to a third-party, Tesoro shall require that third-party to accept an assignment of this Agreement.

8. No Third-Party Beneficiaries. Nothing in this Agreement confers and rights or obligations on any person or entity that is not a party to this Agreement.

9. Counterparts. The Agreement may be executed in counterparts.

10. Governing Law. This Agreement shall be governed by the laws of the State of California.

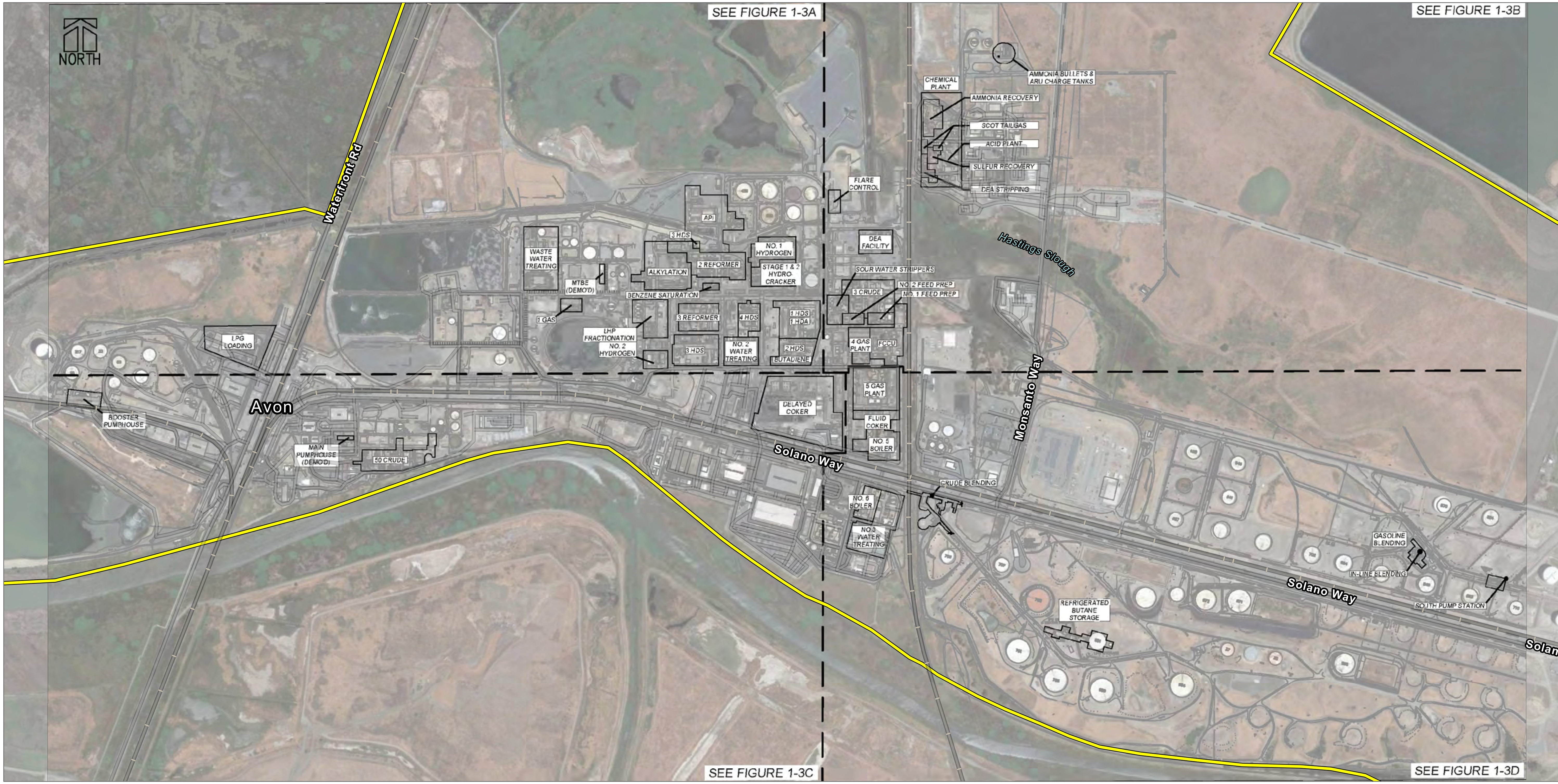
[Signatures on next page]

The County and Tesoro have executed this agreement as specified below.

CONTRA COSTA COUNTY	**TESORO REFINING & MARKETING COMPANY LLC**
______________________________	______________________________
Name: ________________________	Name: Scott S. Hanks
Title: _________________________	Title: Vice President
Date Signed: ___________________	Date Signed: ___________________

[Draft Environmental Impact Report (Link)]

Final Environmental Impact Report (Link)



PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 850 1,700 FEET

1:10,200 1" = 850'

PROJECT: CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA	
TITLE: CURRENT SITE PLAN	
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-3A
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE: MarathonRenewablesFuel.aprx	

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
-- Saved By: RSPRING on 9/15/2021, 11:45:13 AM; File Path: \\employees\gis\arcgis\pro11-PROJECTS\Contra_Costa_County\430721_Marathon_Renewable_Fuels_EIR\2-APRX\MarathonRenewablesFuel.aprx; Layout Name: 2-3 Current Site Plan 11x17L

PROJECT BOUNDARY

NOTES:

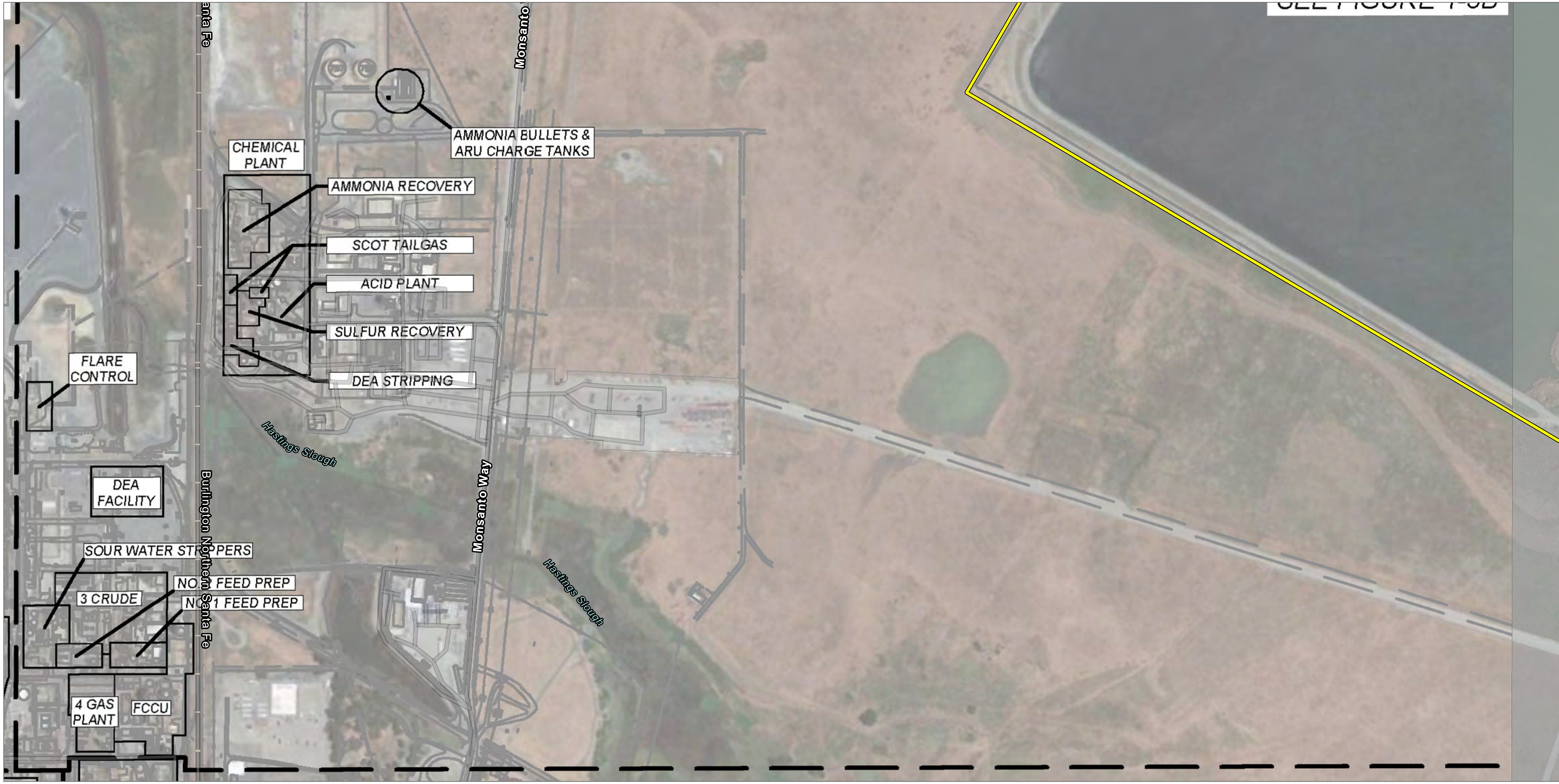
BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT: CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA			
TITLE: CURRENT SITE PLAN			
DRAWN BY:	R. SPRING	PROJ. NO.:	CDLP20-20046
CHECKED BY:	P. DEMICHELE	FIGURE 2-3B	
APPROVED BY:	D. AYERS		
DATE:	SEPTEMBER 2021		
FILE:			MarathonRenewablesFuel.aprx

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
-- Saved By: RSPRING on 9/15/2021, 11:45:13 AM; Layout Name: 2-3 Current Site Plan 11x17L



PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT: CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA	
TITLE: CURRENT SITE PLAN	
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-3C
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE: MarathonRenewablesFuel.aprx	

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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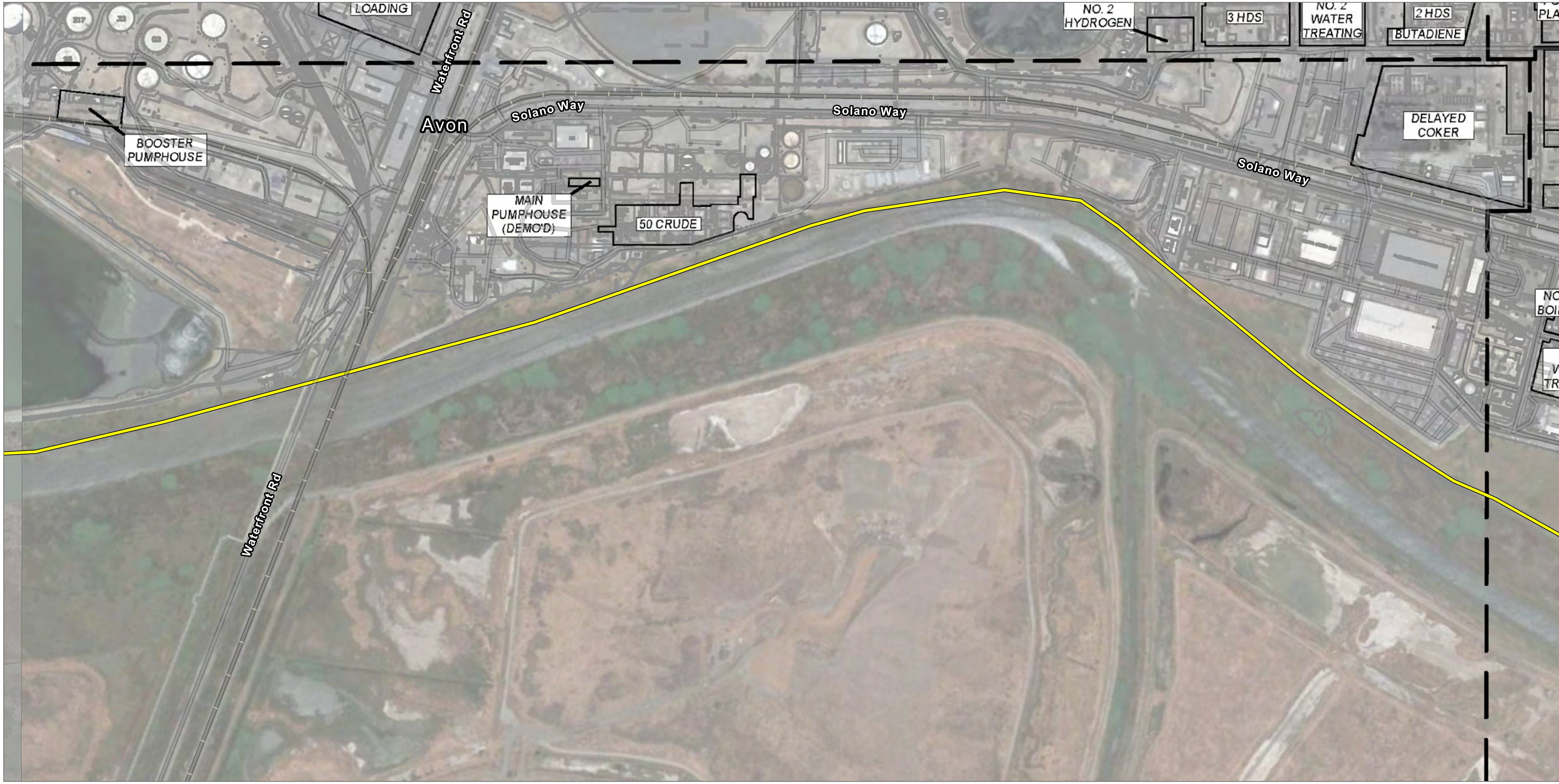

PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 450 900 FEET

1:5,400 1" = 450'

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA		
TITLE:	CURRENT SITE PLAN		
DRAWN BY:	R. SPRING	PROJ. NO.:	CDLP20-20046
CHECKED BY:	P. DEMICHELE	FIGURE 2-3D	
APPROVED BY:	D. AYERS		
DATE:	SEPTEMBER 2021		
FILE:	MarathonRenewablesFuel.aprx		

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT: CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA	
TITLE: CURRENT SITE PLAN	
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-3E
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE: MarathonRenewablesFuel.aprx	

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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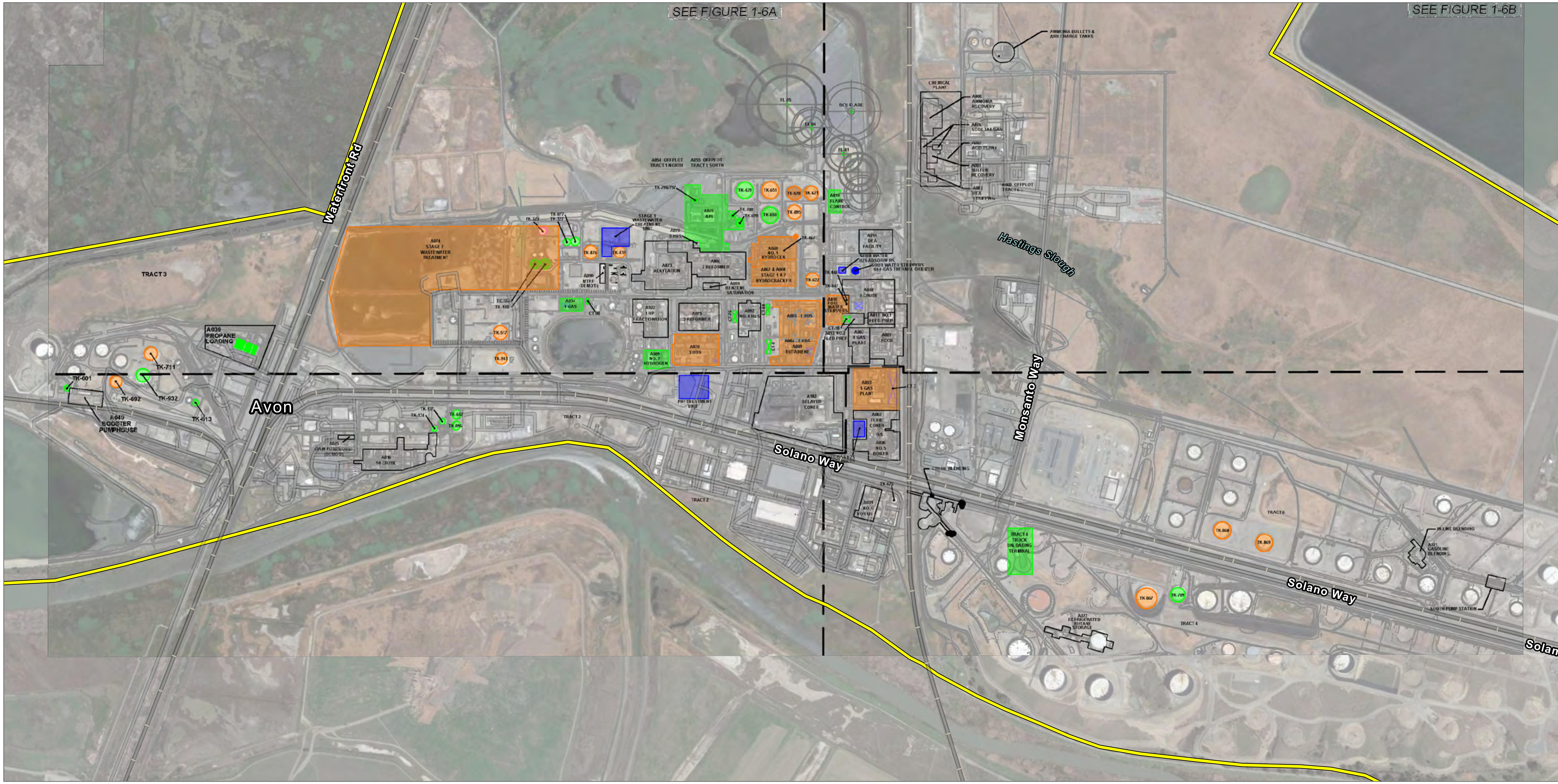

PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 850 1,700 FEET

1:10,200 1" = 850'

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA
TITLE:	PROPOSED REFINERY MODIFICATIONS
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-4A
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE:	MarathonRenewablesFuel.aprx

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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PROJECT BOUNDARY

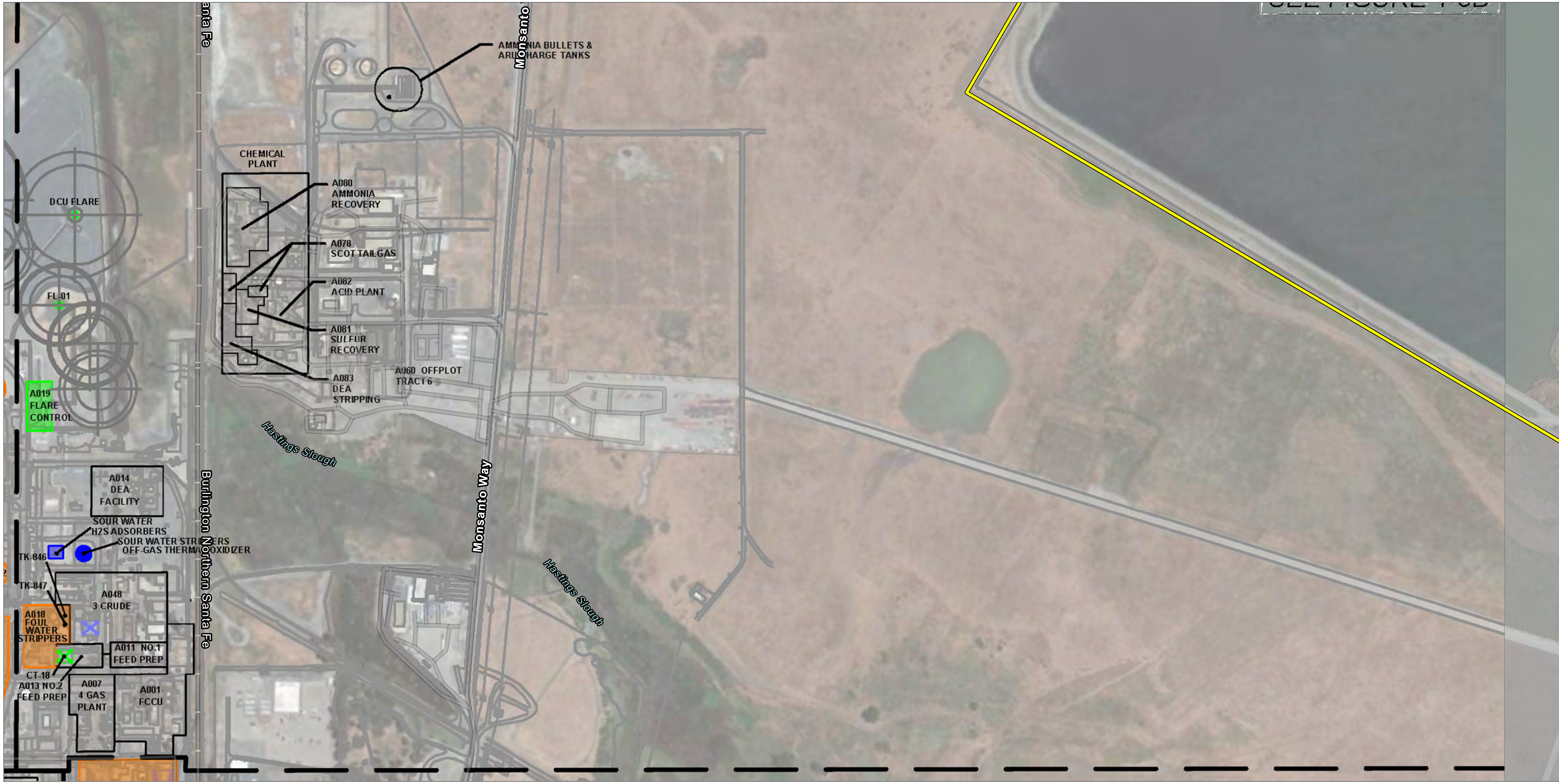
NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA
TITLE:	PROPOSED REFINERY MODIFICATIONS
DRAWN BY:	R. SPRING
CHECKED BY:	P. DEMICHELE
APPROVED BY:	D. AYERS
DATE:	SEPTEMBER 2021
PROJ. NO.:	CDLP20-20046
	FIGURE 2-4B
FILE:	MarathonRenewablesFuel.aprx



PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT: CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA	
TITLE: PROPOSED REFINERY MODIFICATIONS	
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-4C
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE: MarathonRenewablesFuel.aprx	

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 450 900 FEET

1:5,400 1" = 450'

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA
TITLE:	PROPOSED REFINERY MODIFICATIONS
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-4D
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE:	MarathonRenewablesFuel.aprx

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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PROJECT BOUNDARY

NOTES:

BASE MAP: GOOGLE IMAGERY AND ASSOCIATES/ESRI.
DATA SOURCES: MARATHON PETROLEUM CORPORATION

0 400 800 FEET

1:4,800 1" = 400'

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA
TITLE:	PROPOSED REFINERY MODIFICATIONS
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-4E
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE:	MarathonRenewablesFuel.aprx

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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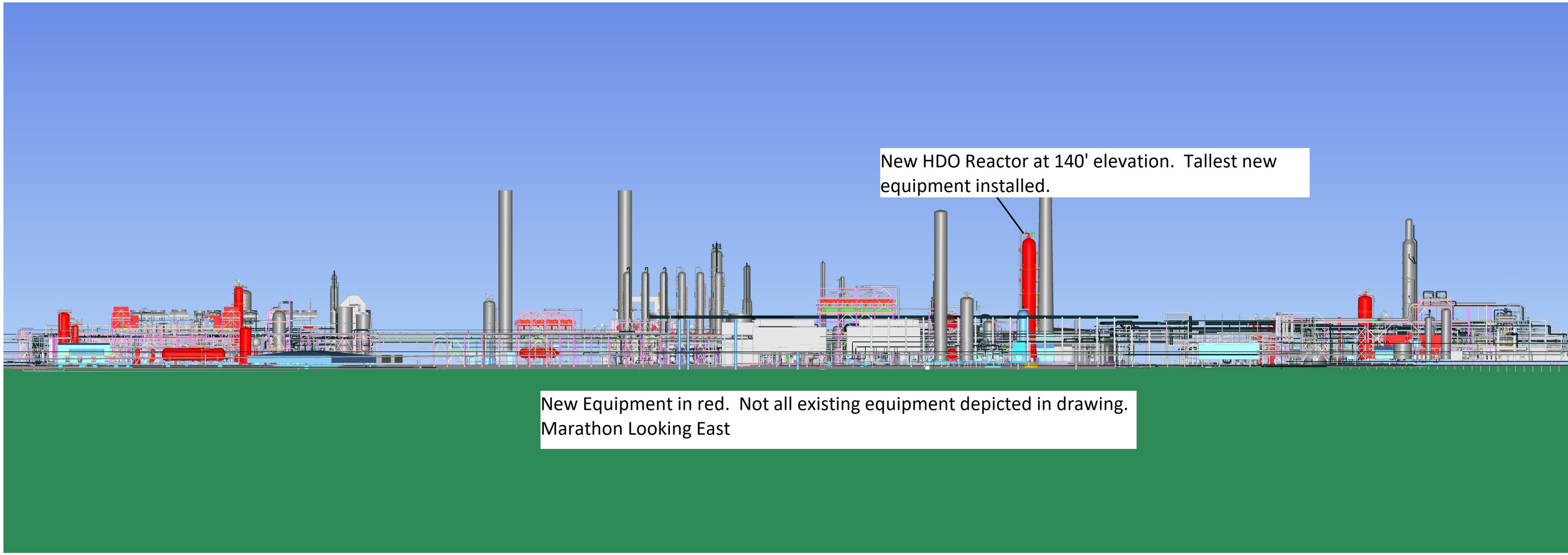

NOTES:

DATA SOURCES: MARATHON PETROLEUM CORPORATION

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA		
TITLE:	PROPOSED DESIGN AND EQUIPMENT LAYOUT (WEST LOOKING EAST)		
DRAWN BY:	R. SPRING	PROJ. NO.:	CDLP20-20046
CHECKED BY:	P. DEMICHELE	FIGURE 2-5	
APPROVED BY:	D. AYERS		
DATE:	SEPTEMBER 2021		
FILE:	MarathonRenewablesFuel.aprx		

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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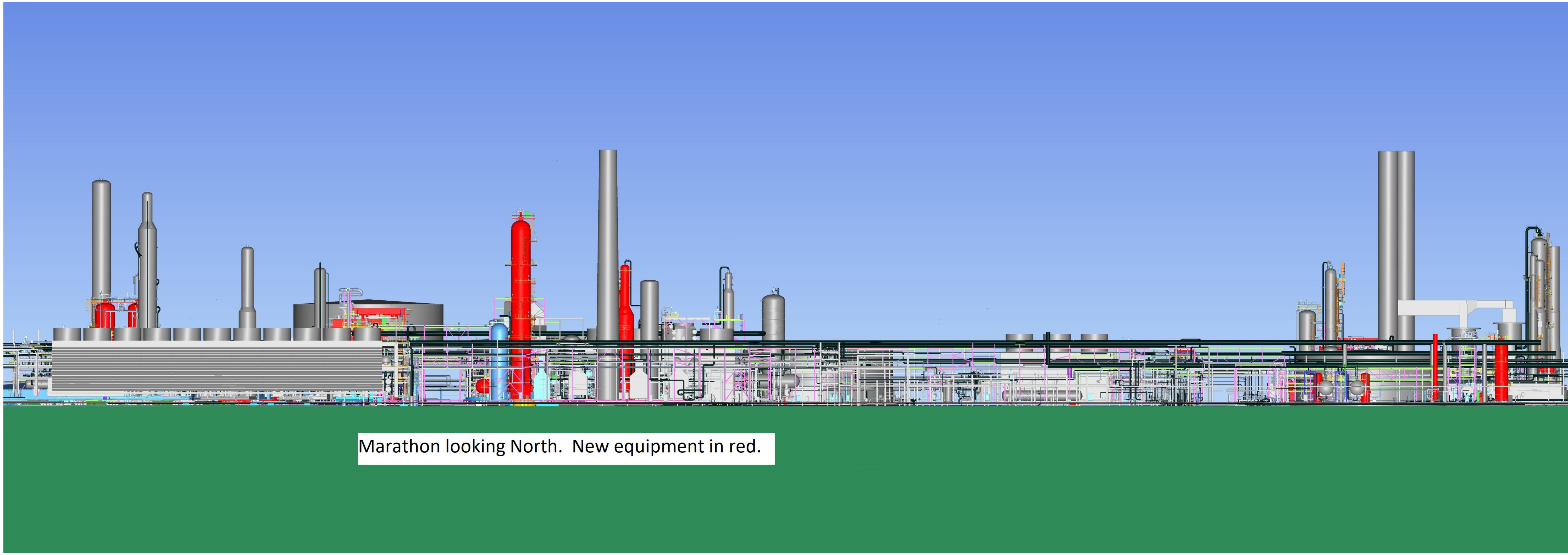

NOTES:

DATA SOURCES: MARATHON PETROLEUM CORPORATION

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA		
TITLE:	PROPOSED DESIGN AND EQUIPMENT LAYOUT (SOUTH LOOKING NORTH)		
DRAWN BY:	R. SPRING	PROJ. NO.:	CDLP20-20046
CHECKED BY:	P. DEMICHELE	FIGURE 2-6	
APPROVED BY:	D. AYERS		
DATE:	SEPTEMBER 2021		
FILE:	MarathonRenewablesFuel.aprx		

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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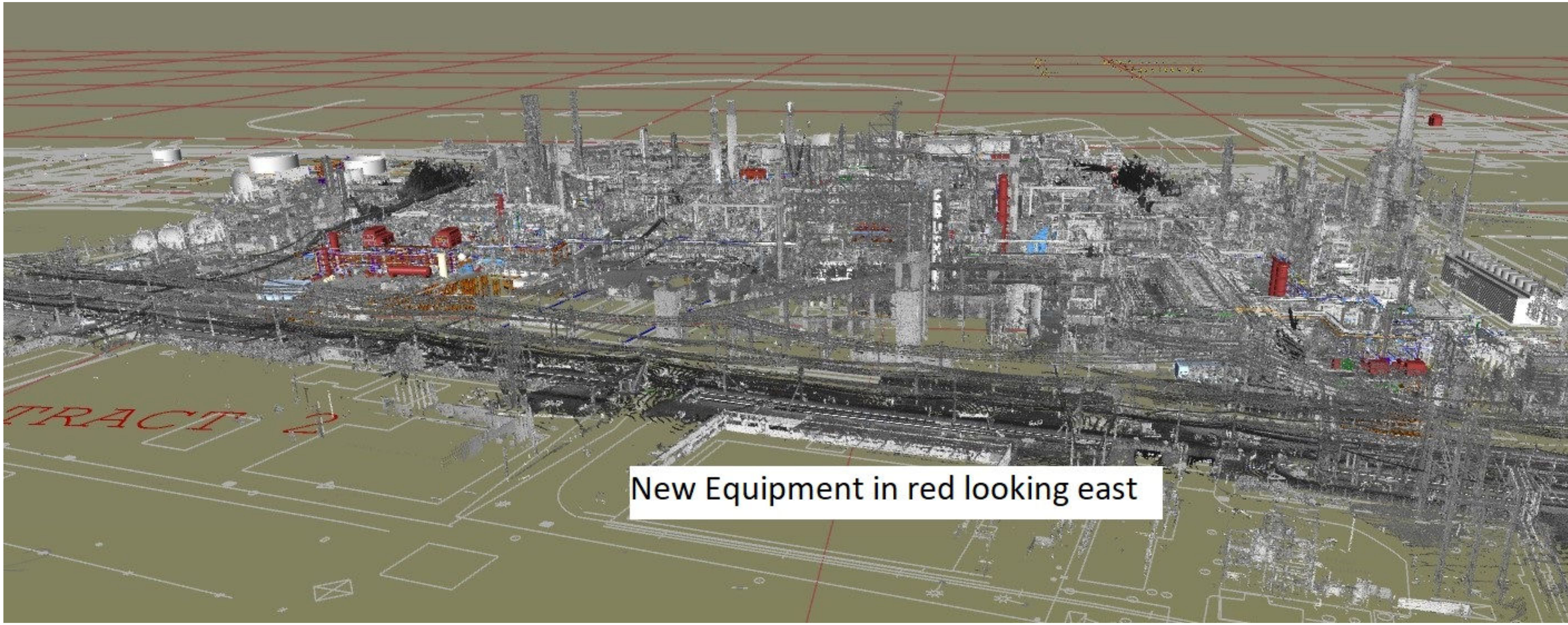

NOTES:

DATA SOURCES: MARATHON PETROLEUM CORPORATION

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA
TITLE:	PROPOSED DESIGN AND EQUIPMENT LAYOUT (LOOKING EAST)
DRAWN BY: R. SPRING	PROJ. NO.: CDLP20-20046
CHECKED BY: P. DEMICHELE	FIGURE 2-7
APPROVED BY: D. AYERS	
DATE: SEPTEMBER 2021	
FILE:	MarathonRenewablesFuel.aprx

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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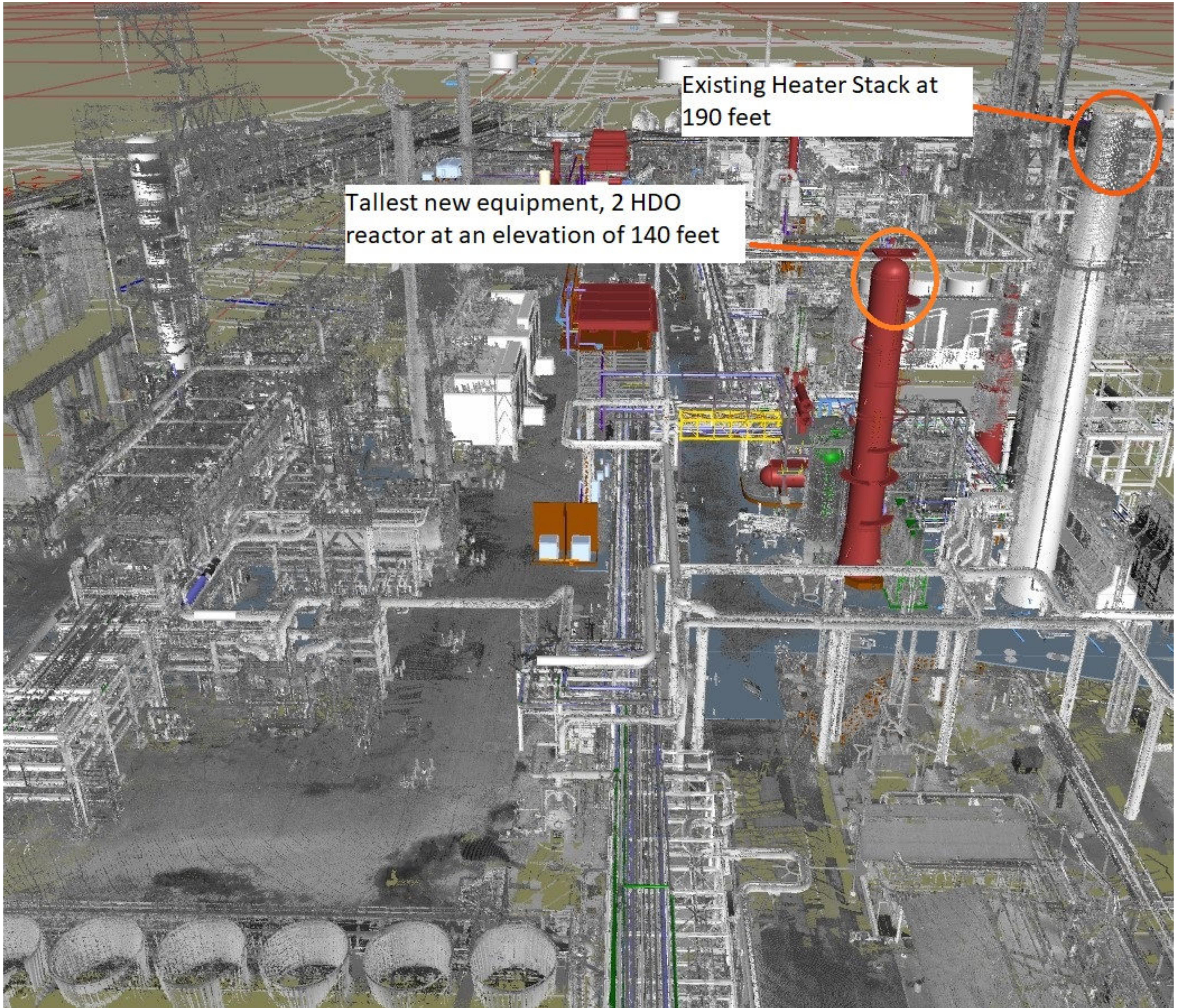

NOTES:

DATA SOURCES: MARATHON PETROLEUM CORPORATION

PROJECT:	CONTRA COSTA COUNTY MARTINEZ RENEWABLE FUELS EIR 150 SOLANO WAY, CONTRA COSTA COUNTY, CALIFORNIA		
TITLE:	**PROPOSED DESIGN AND EQUIPMENT LAYOUT** (LOOKING NORTH)		
DRAWN BY:	R. SPRING	PROJ. NO.:	CDLP20-20046
CHECKED BY:	P. DEMICHELE	**FIGURE 2-8**	
APPROVED BY:	D. AYERS		
DATE:	SEPTEMBER 2021		
FILE:	MarathonRenewablesFuel.aprx		

Coordinate System: NAD 1983 StatePlane California III FIPS 0403 Feet; Map Rotation: -50
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ASIAN PACIFIC ENVIRONMENTAL NETWORK • BIOFUEL WATCH • CENTER FOR BIOLOGICAL DIVERSITY • COMMUNITIES FOR A BETTER ENVIRONMENT • COUNCILMEMBERS CLAUDIA JIMENEZ, EDUARDO MARTINEZ, AND GAYLE MCLAUGHLIN • FRIENDS OF THE EARTH • INTERFAITH CLIMATE ACTION NETWORK OF CONTRA COSTA COUNTY • NATURAL RESOURCES DEFENSE COUNCIL • RODEO CITIZENS ASSOCIATION • SAN FRANCISCO BAYKEEPER • THE CLIMATE CENTER • SUNFLOWER ALLIANCE • 350 CONTRA COSTA COUNTY

March 24, 2022

Re: Appeal of Planning Commission Certification for the Final Environmental Impact Report for the Martinez Refinery Renewable Fuels Project

To the Contra Costa County Board of Supervisors:

Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, 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 Martinez Refinery Renewable Fuels 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); all associated documents in the administrative record; and arguments and information presented before the Planning Commission at its March 23, 2022 hearing.

The decision to certify the FEIR and approve the Project suffers from multiple flaws. First, for the reasons set forth in the Comments, the FEIR fails to meet basic 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 no significant substantive changes in response to the Comments. Second, the FEIR fails to comply with the CEQA requirement to respond to public comments. As discussed in more detail below, the Response fails to provide any substantive response at all to numerous major issues raised in the Comments; and provides a wholly inadequate response with respect to many others. Third, the FEIR presents critical information describing the Project for the first time, so as to deprive the public of the opportunity to comment on that information. And fourth, the Statement of

Overriding Considerations unlawfully purports to override significant impacts that could have been feasibly mitigated.

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 decision 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 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 Staníslaus*, 27 Cal.App.4th 713, 730 (1994), quoting *County of Inyo v. Cíty 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 Comments list in detail the aspects of the proposed technology that must be disclosed in order to adequately evaluate its impacts (Comments at 4-9), but the Response provides only limited partial information. It is only in the Response that the EIR even identifies the proposed HEFA technology by name (Response at 3-37); and it still does not describe essential aspects of its deployment as the basis for the Project.
- *Improper baseline.* The baseline from which the FEIR calculates impacts is continued operation of the Marathon Martinez refinery (Refinery). This baseline is

fictitious, as the Refinery has not operated for nearly two years. The Response fails to address the substantial data specific to the Refinery's operation and reasons for its closure – which, as demonstrated through Commenters' methodical analysis, is quite evidently connected to Marathon's intentional consolidation of operations. Comments at 12-20. The highly general information in the Response concerning overall demand for petroleum products (Response at 3-5 – 9) rebuts none of this – since if such demand actually supported the Refinery's re-opening, that re-opening would have happened already. Marathon's continued maintenance of permits also signifies nothing (see Comment at 12). The inadequacy of the Response concerning the project baseline is further described in the attached technical supplement. The inaccurate baseline skews all other analysis in the FEIR. If the baseline or "no project" scenario is non-operation of the refinery, then the purported decreases in impacts from crude oil refining are actually increases over and above the alternative of non-operation.

- *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 34-37. While the Response purports to address these problems in the Master Response (O12-70, Response at 3-98), it does not actually do so. The fact that the flares are regulated (Response at 3-42) does not relieve the County of the obligation to disclose and properly mitigate their impacts; and is cold comfort to local citizens subjected to increased risks and pollution. The FEIR also continues to exclude any disclosure or analysis of acute short-term episodic air emissions, key to disclosing flaring impact. Comments at 57-58. 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).
- *Failure to account for 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 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 20-34. Commenters cited to the CEQA analysis performed by the California Air Resources Board (CARB) in support of the low carbon fuel standard (LCFS) which specifically directed agencies to review relevant project-specific impacts – making the purported rebuttal in the Response that CARB has "previously evaluated" land use impacts (Response at 3-27) entirely beside the point. Commenters further expressly acknowledged that Marathon may be "unable to specify the exact amount of each

feedstock that will be used" (Comments at 24), making all the statements in the Response that marathon cannot specify "exact" feedstock quantities a red herring. Marathon may not have exact numbers, but Commenters presented available information from which the County could readily have grounded estimates. The suggestion that the needed analysis is too complex or difficult in the context of the DEIR is likewise a red herring, as Commenters pointed out that the calculation formula has already been developed for the LCFS – it just needs to be applied at scale to the Project. Comments at 30.

- *Improper deferment of odor mitigation plan.* The FEIR continues to unlawfully delay addressing potential odors from the project – which 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, "[d]uring the construction phase of the Project." Response at 3-58. 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 Martinez Project is happening in tandem with the much larger and nearby Phillips 66 Rodeo Renewed project, which purports to be the largest of its kind in the world. 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 65-77. The Response fails to address these issues at all, save a conclusory assertion that the FEIR reflects an "appropriate level of generality." Response at 3-33. 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.[1]
- *Inconsistency with California climate pathways.* The Comments presented detailed analysis, backed up by data and 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 - an oversupply of renewable diesel that exceeds the supply anticipated in analysis of California's climate pathways. Comments at 44-58, 72-75. This entire analysis was ignored in the Response.
- *Failure to adequately mitigate transportation risk impacts.* The Comments provided detailed concerns with regard to marine impacts, concerns which were dismissed by

[1] 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.

> the County under the assumption that non-petroleum feedstocks will react to cleanup methodologies identically to petroleum. O12-127, 138. While support is offered for the assumption that petroleum and non-petroleum finished diesel products react similarly, 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. While the County's response states that Marathon will update the Northern California Blanket Oil Spill Response Plan to include non-petroleum feedstocks, no such commitment is made in the DEIR at the cites provided, and no legal requirement to respond exists. Requiring such response from non-Project assets is outside of the County's jurisdiction, and so should be required of Project assets as a mitigation measure specific to this project.

This list is not a complete catalogue of all of the deficiencies of the FEIS. 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 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. The Comments were extraordinarily thorough and detailed. Commenters presented hundreds of pages of careful analysis, backed up by technical reports and supported by extensive citation of peer reviewed studies and other materials, all provided to the Department to aid its review. In the Response, the Department simply ignores large swaths of that analysis.

A great many comments simply receive no substantive response at all. Although the Response dutifully catalogues by number each point made by Commenters and purports to address it, this superficially meticulous approach cannot disguise the fact that the Response neglects to actually address a great many such points. The Response contains a "Master Response," which is a narrative discussion concerning some of the major comment topics (baseline, cumulative impacts, land use impacts, alternatives, public safety). When addressing Commenters' specific catalogued points, the Response frequently provides only a single sentence cross-referencing to a section of the Master Response – yet in a great number of cases the Master Response does not actually talk about the point at all.

The discussion in the previous sections provides two particularly important examples of this flawed approach. Commenters provided detailed analysis of (among many other things) the potential problem of biofuel oversupply as it concerns California's climate goals (44-48, 72-75); and the problem of runaway reactions and corrosion of equipment as potential contributors to process upsets (Comments at 35). Both analyses were supported by extensive discussion and explanation in the attached technical reports (which cite in turn to peer-reviewed literature). The Response cross-references in both cases to the Master Response (O12-85 cross-referencing Master Response 4; O12-70 cross-referencing Master Response 5), but in neither case does the cross-referenced section directly address the comment. Additionally, with respect to the oversupply point, large portions of Commenters' meticulous quantitative analysis are simply dismissed with "comment noted" (O12-86-88).

In many other cases, the response falls far short in level of detail to the thoughtful and thorough critique provided by Commenters and/or relies upon conclusory assertions as to why the comment should be summarily dismissed without response. For instance, Commenters' concerns with the EIR's failure to adequately evaluate cumulative impacts (Comments at 65-77) are dismissed with the summary assertion that the FEIR's high level of generality is appropriate (Response 3-33). Although the Comments had pointed out that the list of nearby projects used to assess cumulative impacts included many that are irrelevant to determining the Project's actual cumulative impacts (Comments at 63-64, referencing the inclusion of a self-storage unit development and conversion of a billboard to digital format), the Response persists in referencing these projects as "similar," without further explanation.

These problems are pervasive in the Response. To ensure compliance with CEQA, the Board of Supervisors should grant this appeal and order the Department and Commission to thoroughly respond to each substantive comment presented, as mandated by CEQA Guidelines § 15008(c).

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

The FEIR evaluates two alternatives in addition to the no project alternative: a green hydrogen 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 throughput. The staff report specifies that the project is "anticipated to process approximately" 48,000 barrels per day (bpd) of feedstock; but nothing in the approval conditions limits throughput to that amount. This is a fatal flaw in the CEQA process. The FEIR analyzed the impact of 48,000 bpd, yet nothing constrains the Project from processing more feedstock than that, with attendant greater impacts.

Given these foundational failures to comply with CEQA, the FEIR and proposed approval conditions as presented should be rejected, with orders that the Department make findings among the alternatives evaluated based upon evidence in the record. Furthermore, findings regarding throughput volume must be reflected in a condition of approval that actually governs throughput.

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

While the Response is overall sketchy on detail, in a few places it provides for the first time, information describing the Project. This is most notably true with respect to the proposed technology, HEFA, that the Project will deploy. Commenters, through their technical expert, independently discerned and identified HEFA as the Project technology, and in doing so described its many risks and challenges. Comments at 34-52. However, as noted above, the DEIR did not even name HEFA as the proposed technology, much less describe it. The Comments identified the many aspects of HEFA technology that should have been disclosed and addressed. Comments at 5-9. While the Response does not by any means disclose all of the requested information on HEFA, it does specify for the first time that HEFA will be the technology relied upon by the Project.

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 the basic nature of a proposed project only in the FEIR, when opportunity for meaningful public comment has passed. For this reason, the DEIR should be revised to include a thorough description of HEFA technology, containing the components outlined in the Comment, and ordered recirculated in response to this appeal.

V. 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 (including safety impacts and land use impacts), much less mitigate them. And as noted above, the 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.

VI. Conclusion

For the foregoing reasons, 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 so as to comply fully with CEQA; and that they address through thorough disclosure and analysis all issues raised in the Comments.

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 CALIDORNIA • 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 (joseph.lawlor@dcd.cccounty.us)[1]

Joseph W. Lawlor Jr., AICP
Project Planner
Contra Costa County
Department of Conservation and Development
30 Muir Rd
Martinez, CA 94553

Re: Martinez refinery renewable fuels project (File No. CDLP20-02046) – comments concerning draft environmental impact report

Dear Mr. Lawler:

Asian Pacific Environmental Network, Biofuelwatch, California Environmental Justice Alliance, Center for Biological Diversity, Communities for a Better Environment, Citizen Air Monitoring Network, 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, and 350 Contra Costa (collectively, Commenters) appreciate this opportunity to submit comments concerning the Contra Costa County's Draft Environmental Impact Report (DEIR) for the Martinez refinery (Refinery) renewable fuels project (Project) proposed by Marathon Petroleum Corporation (Marathon).

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 is unprecedented in scale and scope. A conversion of an existing refinery of this size is new 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 Martinez 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 – particularly given that the Refinery had shut down its crude processing operations at the time it proposed 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 chemistry, hydrogen production and input requirements (a major emissions generator) and refining temperature and pressure (which implicates process upset risks),– that

[2] *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("*Laurel Heights I*").

are essential to an assessment of the proposed new operations on the surrounding community.

- *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 failed to either describe the increase and change in use of marine facilities in connection with the Project, or evaluate the many risks associated with it.
- *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 bean 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 Phillips 66 Rodeo 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 have remained closed. Accordingly, the DEIR should have considered the environmental impacts associated with subsequent legal requirements for site decommissioning.
- *Deficient project alternatives analysis.* The DEIR 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 using electrolytic hydrogen production. It 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 March 22, 2021 CEQA scoping comments on the Notice of Preparation (Scoping Comments) that these topics be considered, and provided voluminous documentation concerning each.[3] 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.[4]

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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[3] 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, Martinez refinery renewable fuels project (File No. CDLP20-02046) – comments concerning scoping submitted via electronic mail and via overnight mail (Mar. 22, 2021), available at Contra Costa County Department of Conservation & Development Community Development Division. Appendix NOP: Comments on Notice of Preparation (NOP) https://www.contracosta.ca.gov/DocumentCenter/View/72958/Appendix-NOP (accessed Dec. 8, 2021).

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

TABLE OF CONTENTS

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/Wildlífe Rescue Center v. County of Stanílslaus*, 27 Cal.App.4th 713, 730 (1994), quoting *County of Inyo v. Cíty 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 DEIR 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 land use, 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

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

- 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.
- Marine terminal modificatios and changes in use of the terminal, including an increase in ship traffic associated with the Project
- The anticipated and technically achievable operating duration of the project.

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

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

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

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

a. HEFA as the Proposed Type of Processing

As noted above, the DEIR never once mentions that HEFA is the technology the Project would employ. It can be discerned nonetheless that HEFA is, in fact, the proposed technology, based on the Project's sole reliance upon repurposed refinery hydrotreaters and hydrocrackers for feed conversion to fuels, and upon repurposed refinery hydrogen plants to produce and supply hydrogen for that hydro-conversion processing. This is confirmed by independent expert review of the Project.[2] [3] [4]

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

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[2] Karras, G, *Changing Hydrocarbons Midstream*; technical report and accompanying supporting material appendix for Natural Resources Defense Council, San Francisco, CA, June 2021 (Karras, 2021a).
[3] Karras, G, *Unsustainable Aviation Fuel;* technical report for Natural Resources Defense Council, San Francisco, CA, August 2021 (Karras, 2021b).
[4] Karras, G, *Technical Report in Support of Comments Concerning Marathon Martinez Renewable Fuels Project*; technical report prepared for Natural Resources Defense Council, San Francisco, CA, December 2021 (Karras, 2021c).

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:[5] [6] [7] First, HEFA biofuels can be produced by repurposing 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.[8] Moreover, site-specific differences in process design conditions[9]—which have been reported in other CEQA reviews for oil refining projects[10]—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.[11] The DEIR does not

[5] Karras, 2021a and 2021b.
[6] Karras, 2021a.
[7] Karras, 2021b.
[8] *Id*.
[9] 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 in some cases, even how those operating conditions interact across refining processes to affect overall hydrogen demand when processing feedstocks of various qualities.
[10] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model.
[11] *Id*.

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 that 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 production, which, because of its production chemistry, can emit roughly ten tons of carbon dioxide per ton of hydrogen produced.[12] The DEIR further fails to describe the high *and* variable carbon intensity of fossil gas hydrogen technology among specific plants and refineries;[13] 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.[14] 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.[15] [16] 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.

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[12] Karras, 2021a.
[13] Sun et al. 2019. Environ. Sci. Technol. 53: 7103–7113. DOI: 10.1021/acs.est.8b06197, https://pubs.acs.org/doi/10.1021/acs.est.8b06197.
[14] Karras, 2021a,
[15] *Id.*
[16] BAAQMD §12-12-406 causal reports; reports relevant to the Project accompany this Comment; recent reports available at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports

2. The DEIR Fails to Disclose Adequate Information Concerning HEFA Feedstocks

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.[17] 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.

The DEIR, however, provides extremely minimal information concerning Project feedstocks. The DEIR merely lists three types of materials that feedstock for the Project is "expected to include": distillers corn oil (DCO), soybean oil (SBO), and previously-rendered fats (tallow). DEIR at 2-36. It does not reflect a commitment by Marathon to use these feedstocks exclusively. It does additionally state, "As technology evolves, other biological fuel sources such as used cooking oils, and plant and animal processing by-products, may also be used as feedstock using substantially the same equipment and processes as those proposed under the proposed Project." *Id.* This cryptic reference to the possibility that other feedstocks may be used "as technology evolves" is entirely insufficient. What technology is potentially evolving, and what additional feedstocks would such evolved technology allow? What is the availability of such feedstocks?

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

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

3. The DEIR Fails to Disclose a Project Component Designed to Maximize Jet Fuel Production

During and after proposed Project construction, Marathon would configure the repurposed refinery to swing between production targets to maximize HEFA diesel production and those to maximize HEFA jet fuel production. The capability and intent to do so is clear from

[17] *Id.*

the existence of two hydrocracking reactors, which the Project proposes to operate in series.[18] However, the Project's ability to effectuate this flexibility in production targets depends upon Project aspects not disclosed in the DEIR. Specifically, the DEIR does not disclose the need to boost low jet fuel yield for mid-term Project viability; and neither does it disclose how the Project will achieve that end - including the need to add intentional hydrocracking to HEFA processing for boosting jet fuel yield, and the capability of the 1st Stage Hydrocracker configuration included in the Project to do just that. These steps would increase Project impacts.[19]

B. The DEIR Fails to Sufficiently Describe Changes Affecting the Project's Marine Facilities

The DEIR fails to adequately describe either the marine terminal modifications or changes in use of the terminal.. In the absence of such description, the public is not in a position to evaluate potential Project impacts on such resources.

The DEIR fails to provide an estimate or evaluation of how many ships are projected to use the marine facilities under the new plan. The five-year average for vessel calls was, according to the DEIR, 143. DEIR Table 3-4.

Table 3-4 Comparative Vehicle and Vessel Traffic for Marathon Refinery, 1-year, 3-year Average, and 5-year Average

Vessel or Vehicle	Units	1-year (2019-2020)	1-year (2018-2019)	3-year Average (2017-2020)	5-year Average (2015-2020)
Truck	Miles Traveled	2,837,991	4,559,507	3,972,015	4,146,210
Train	Miles Traveled	2,380	4,820	4,154	4,605
Vessel	Calls	124	161	150	143

Source: Marathon Petroleum Corporation, 2021

No description is provided about whether that number would increase or decrease under the Project.[20] Instead, the public is expected to flip back and forth between different sections and try to estimate for itself whether various levels of feedstocks and finished product traveling across

[18] DEIR pp. 2-20, 2-21: Table 2-1 (separate 1st and 2nd stage hydrocracker components to be deployed for different types of processing).
[19] Karras 2021c.
[20] To the extent this information is buried somewhere in the approximately 450 pages of the DEIR, or in the thousands of pages of appendices, it is not sufficiently clear and/or accessible. For instance, buried in the Air Impacts section of the DEIR is the statement that "Overall, the number of vessel calls at the Amorco MOT is expected to decrease, and the number of vessel calls at the Avon MOT is expected to increase compared to past actual operations." DEIR 3.3-27. No precise information is estimated or given. This type of obfuscation and hiding the ball is not permitted under CEQA. Another random statement, unsupported or referenced, mentions that "[w]ith the Project, it is estimated there will be an increase in deep-draft vessels." DEIR 3.4-37. Impacts must be discussed in a plain, straightforward manner that is easily accessible by the public. That "the Project does not change the unloading/loading capacities of these two MOTs" is irrelevant. *Id*. The DEIR must evaluate proposed conditions against existing conditions, as well as against the various alternatives, including the No Project Alternative. This DEIR fails to do so.

Marathon's wharves constitute an increase in impacts to marine resources. CEQA requires more.

The description of the modifications contemplated under the Project constitute two paragraphs, and the descriptions about how operations would change constitute another two short paragraphs. At the Avon MOT, for instance, we are told that "part of the system of pipes and hoses would be reconfigured to keep the finished petroleum products separate from the renewable feedstocks, and to facilitate transmission of the renewable feedstock through receiving pipelines." DEIR 2-17. That, and the rest of the paragraph describing minor details of the conversation, are the only analysis provided. "[T]he Avon MOT would change from a point of distribution to primarily a facility for receiving of renewable feedstocks." DEIR 2-36. "In total, the Avon MOT would receive an average of 70,000 bpd of renewable feedstocks, gasoline product for distribution, and naptha for transfer." DEIR 2-37. No further specifics are given. Nothing in this description tells the public how much of each feedstock, gasoline product, and naptha will be coming over this wharf, what kinds of vessels will be bringing it, what the chemical composition of the feedstocks and other products will be, what kinds of equipment might be needed should a spill at the Avon MOT occur, how these feedstocks and other products differ from the petroleum products the refinery typically handles and what types of equipment might be more or less effective at addressing these differences, etc. The list of missing details is far longer than the bare 9- and 7-line paragraphs provided in the DEIR. DEIR 2-17, 2-36 – 2-37.

Similarly, the DEIR neglects to give required details of the changes in use expected at the other marine terminal attached to the Marathon Refinery, the Amorco MOT. Here, the public is only told that there will need to be "modifications … to accommodate the smaller marine vessels (25,000- to 50,000-barrel capacities) expected to dock there." The only volume information the public is given is that "use of the Amorco MOT would change from a receiving facility to primarily a distribution facility for loading of renewable diesel product for outbound shipments from the Refinery. Product from the Refinery would be distributed from the Amorco MOT at an average rate of 27,000 bpd of renewable fuel." DEIR 2-37. Again, the public is not told how many smaller (or larger) vessels are expected, what they will be carrying, and all the other questions left unanswered by the description of the Avon MOT, as well. Again, the DEIR only provides two 8-line paragraphs. This is glaringly insufficient.

These deficiencies are of particular import given that the DEIR suggest in places – albeit with extreme lack of clarity – that ship traffic may, in fact, increase in connection with the Project. One among a series of confusing tables buried in Appendix B to Appendix AQ-GH appears to show an increase in pre- to post-Project (though the specific baseline period used is not explained) increase of number of trips to the Avon MOT of 144, from 120 trips pre-Project to 364 trips post-Project. DEIR Appendix AQ-GH, Appendix B, Table B-7. Similarly, onside annual pre-Project emissions are estimated (confusingly) as 210 trips, while total post-Project trips are estimated at 404. *Id.* This at least doubling of the amount of vessel traffic is not adequately evaluated or discussed in the DEIR.

Thus, 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 ("Marathon recently suspended refining of crude oil in April 2020," DEIR ES-3), the Project may contemplate a significant increase in the amount of feedstock and other potential pollutants crossing through the marine terminal. The public can only speculate, but any such increase represents a significant impact to the marine environment around the refinery, in San Francisco Bay, and all along the routes the shipping transportation will take when delivering and distributing products from the proposed Project. These routes and numbers of ships must be provided in to the public, with adequate opportunity to comment given.

C. The DEIR 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 Marathon 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.[21]

III. THE DEIR IDENTIFIES AN IMPROPER BASELINE FOR THE PROJECT [22]

The DEIR commits a major error in using an operating crude oil refinery as a baseline for determining impact significance. Marathon made a clear and widely-reported declaration last year that it no longer intends to refine crude oil at this facility.[23] As discussed below, even though crude oil demand rebounded this year after the initial pandemic-related drop in 2020, Marathon did not re-commence refining operations. It is clear that Marathon has no intention of resuming crude oil refining at the Martinez site for reasons pertaining to operational economics.

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[21] 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.

[22] 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."

[23] *See, e.g.*, "Marathon Petroleum to Close its Martinez Refinery and Convert it to an Oil-storage Facility," *The Mercury News* August 1, 2020.

A. CEQA Requires Use of an Accurate Baseline

The CEQA baseline, with a limited exception,[24] must "describe physical environmental conditions as they exist at the time the notice of preparation is published." CEQA Guidelines § 15125. "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 (*Communities for a Better Environment*). 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."). Certainly, using an operating facility as a baseline where the operator has definitively declared a definitive intention to end operations and carried through with it finds no support in the law. *See Association of Irritated Residents v. Kern County Board of Supervisors* (2017), 17 Cal.App.5th 708, 728 (use of operating crude oil facility as baseline was appropriate where the owner "has consistently stated its intention to continue refining at the site," and had continued operations to the extent possible).

Thus, as discussed in the section below, the DEIR analysis concerning baseline identification is legally deficient. The issue is not whether the Refinery's emissions fluctuated over time when it was processing crude oil. DEIR at 3-2, citing CEQA Guidelines § 15125(a)(1). It is that the Refinery *is no longer processing crude oil.* The DEIR cites *Communities for a Better Environment* and the CEQA guidelines for the proposition that agencies have leeway in setting a baseline "where an *existing* operation is present," and may look to past years ... "to characterize that *existing* operation,"; but here *there is no existing operation here to characterize.* DEIR at 1-2, 1-3 (emphasis added). That key fact must determine the establishment of a baseline.

B. Available Evidence Makes Clear that Marathon Made and Carried Out a Decision to Permanently Cease Crude Refining Operations at the Refinery

Determining a proper baseline is critical to all aspects of the DEIR, rendering much of its analysis fatally flawed if the baseline is wrong. If, in fact, the Refinery has been forced by current circumstances to cease crude oil production, then baseline conditions (and the no project alternative) would almost certainly have less environmental impact than any Project alternative.

Available evidence demonstrates that the baseline chosen by the County is simply wrong. It is abundantly clear that Marathon does not, in fact, intend to re-commence crude oil processing at the Refinery if the Project application is not approved. This fact renders key portions of the DEIR analysis quite simply fictional. The Project Description states that an objective of the Project is to "Eliminate the refining of crude oil at the Martinez Refinery while preserving high quality jobs" (DEIR at 1-2); yet crude refining has already been eliminated there. The description

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[24] A baseline reflecting projected future conditions is appropriate where "use of existing conditions would be either misleading or without informative value to decision makers and the public." CEQA Guidelines § 15125(a)(1) and (2).

of "Existing Refinery Operations," while acknowledging at the end that the Refinery has been idled, is otherwise written as though it were still functioning, describing transport and other operations in the present tense. DEIR at 1-3 – 4.

The most important piece of information that would support this conclusion is simply the fact that the Refinery has closed – long before the reasonable prospect of a Project approval, and before the Application was developed and submitted. Petroleum refining operations ended there on April 28, 2020.[25] In July 2020, Marathon asserted that closure was permanent with no plans to restart the refinery.[26] This Project launched later. Marathon was "evaluating the possibility" of this Project in August,[27] began "detailed engineering" for the Project during October–December 2020,[28] and "approved these plans" on February 24, 2021.[29] The Project Description does not propose restarting oil refining as an alternative to the Project.

Beyond the fact of the Refinery's current closed state, there is extensive information indicating that the decision to close the Refinery was likely not grounded in plans to pursue the Project, but rather was the result of economic factors and resultant business directions independent of the possibility of re-purposing the refinery to produce biofuels. As discussed in the sections below, available evidence – not disclosed in the DEIR although it was referenced in the Scoping Comments – indicates that the closure of the refinery was based on economic factors unrelated to the Project. Marathon's failure to re-open the Refinery when refined product demand rebounded in 2020 further confirms that the closure decision was permanent. The DEIR should have disclosed that the real question is not whether the Refinery will close – it already has - but whether the Project will enable Marathon to re-purpose its stranded asset, and if so under what conditions and mitigation requirements.

1. Available Evidence, Not Disclosed in the DEIR, Indicates that Marathon Closed the Refinery for Economic Reasons Unrelated to the Project

Available evidence strongly indicates that the Refinery closed as part of a consolidation of refining assets. Refining assets follow the rule of returns to scale. Over time, smaller refineries expand or close.[30] Consolidation, in which fewer refineries build to greater capacity, has been the trend for decades across the U.S.[31] The increase in total capacity concentrated in

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[25] April 28, 2020 Flare Event Causal Analysis for Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758, submitted to the Bay Area Air Quality Management District dated June 29, 2020. Accessed from www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports.
[26] Workshop Report, Draft Amendments to Regulation 6, Rule 5: Particulate Emissions from Petroleum Refinery Fluidized Catalytic Cracking Units. January 2021. Bay Area Air Quality Management District: San Francisco, CA. *See* p. 14 FN; captions of tables 1, 2, 6, 8–10.
[27] August 25, 2020 email from A. Petroske, Marathon, to L. Guerrero and N. Torres, Contra Costa County.
[28] US Securities and Exchange Commission Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2020, by Marathon Petroleum Corporation. Accessed from https://www.marathonpetroleum.com/Investors/ *See* p. 50.
[29] *Id*.
[30] Meyer, D.W., and Taylor, C.T. The Determinants of Plant Exit: The Evolution of the U.S. Refining Industry. Working Paper No 328, November 2015. Bureau of Economics, Federal Trade Commission: Washington, D.C. https://www.ftc.gov/system/files/documents/reports/determinants-plant-exit-evolution-u.s.refining-industry/wp328.pdf
[31] *Id*.

fewer plants[32] further reveals returns to scale as a factor in this consolidation. Access to markets also is a factor. The domestic market for engine fuels refined here is primarily in California and limited almost entirely to the West Coast.[33] In this context, Tesoro, Andeavor, and Marathon expanded refining capacity elsewhere in this market instead of at the Martinez Refinery—investment decisions that created the largest refinery on the West Coast in Los Angeles[34] and left Marathon with *extra* capacity in California, and across the West Coast, even after its Martinez refinery closed. This is shown by federal refining capacity data.[35] *See* Table 1.

Table 1. Total Operable Atmospheric Crude Distillation Capacity of West Coast Refineries Owned by Marathon Petroleum Corp. / Andeavor / Tesoro Refining and Marketing, 2010–2021. [a]

Capacities in barrels per calendar day (b/cd) from January 1 of each year.

Year	Los Angeles, CA	Martinez, CA	Anacortes, WA	California Subtotal	CA & WA Subtotal
2010	96,860	166,000	120,000	262,860	382,860
2011	94,300	166,000	120,000	260,300	380,300
2012	103,800	166,000	120,000	269,800	389,800
2013	103,800	166,000	120,000	269,800	389,800
2014	355,500	166,000	120,000	521,500	641,500
2015	361,800	166,000	120,000	527,800	647,800
2016	355,170	166,000	120,000	521,170	641,170
2017	364,100	166,000	120,000	530,100	650,100
2018	341,300	166,000	120,000	507,300	627,300
2019	363,000	161,500	119,000	524,500	643,500
2020	363,000	161,000	119,000	524,000	643,000
2021	363,000	—	119,000	363,000	482,000
	Growth in capacity from 2010–2020 in barrels per day:			261,140	260,140
	Growth as a percentage of Martinez capacity on 1/1/20:			162 %	162 %
	Growth in capacity from 2010–2021 in barrels per day:			100,140	99,140

[a] Data from USEIA, 2021. *Capacity Data by Individual Refinery;* U.S. EIA; www.eia.gov/petroleum/refinerycapacity/archive.

Since refineries wear out in the absence of sufficient reinvestment,[36] and run more efficiently when running closer to full capacity, those decisions to invest and expand elsewhere set the stage for refining asset consolidation. And indeed, Marathon informed its investors that it expected to complete the "consolidation" and expansion of its refining facilities in Los Angeles in the first quarter of 2020,[37] just before it finally closed the Refinery in April. In fact, closing the Refinery lets Marathon run its Los Angeles and Anacortes refineries closer to full.

This consolidation should be understood in the context of a declining market, which further reinforces the evidence that the Refinery closure is independent of plans for the Project.

[32] *Id*.
[33] PADD 5 Transportation Fuels Markets, September 2015 (PADD 5 2015), U.S. Energy Information Administration (EIA). https://www.eia.gov/analysis/transportationfuels/padd5/
[34] Marathon Petroleum Corp., 2019 Annual Report, Part I, p. 9 (2019 Annual Report). https://www.annualreports.com/HostedData/AnnualReportArchive/m/NYSE_MPC_2019.pdf.
[35] EIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021, and previous years; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity (USEIA 2021).
[36] *See* G. Karras, *Decommissioning California Refineries: Climate and Health Paths in an Oil State* at 20, *available at* https://www.energy-re-source.com/decomm (July 2020) and supporting material (Karras 2020).
[37] 2019 Annual Report. *See* "From the Chairman and CEO" at p. 1.

The Refinery was losing its market. Its domestic market is limited to the West Coast,[38] and West Coast demand for refined products peaked years ago, starting an unprecedented decade-on-decade decline.[39] This decline is accelerating in part because electric vehicles are replacing gasoline demand. Going three times as far per unit energy as gasoline-burning cars, and with fewer moving parts to wear out and fix along the way—e.g., no transmission—battery-electric vehicles will cost less overall.[40] State climate policy is intentionally encouraging the switch to EVs, as part of a policy to phase out most gasoline and diesel vehicles rapidly.[41]

In light of these trends, the COVID-19 pandemic cannot be fingered as the sole cause of the Refinery shutdown, or evidence that it is temporary. Although COVID-19 resulted in an unprecedented temporary curtailment in statewide refining rates,[42] no other California oil refinery closed during the pandemic. COVID further revealed the limits of refineries' increasing reliance on exports to foreign markets, which command lower prices than we pay here, as a way out of this self-inflicted crisis – but again, the impact of that reliance inherently fell harder on the Refinery. Here, the Refinery's setting, landward of a shallow shipping channel that forces tankers to partially unload before calling at Martinez, wait for high tide to sail to and from Martinez, or both,[43] put it in a worse export position than its competitors in Richmond and Los Angeles—and crucially, targeted Martinez rather than Anacordes for closure in the consolidation described above. All available information thus indicates that it was simply more economical – for reasons predating both COVID-19 and the Project – for Marathon to run two refineries closer to full than it was to run three refineries closer to empty. Marathon closed the Refinery in the face of declining fuels demand, when it had more than replaced the capacity of this refinery in Los Angeles, as shown in Table 1. At worst, COVID only accelerated its closure.

Thus, it is highly significant that in the competition between major California refineries over a shrinking, climate-constrained, and electric vehicle-challenged petroleum fuels market, this one closed first; and no other has closed. It lost that competition after Marathon and former owners of this refinery prioritized investments in refining assets elsewhere instead of Martinez. Those investment decisions effectively divested from the competitiveness of this refinery, and were implemented before COVID-19 and before this Project was conceived, engineered, or proposed. These facts must be considered in evaluating the true "no project" baseline that accurate environmental review will depend upon in the DEIR.

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[38] PADD 5 2015.

[39] West Coast (PADD 5) Supply and Disposition, EIA February 26, 2021. http://www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm; New Climate Threat: Will Oil Refineries make California the Gas Station of the Pacific Rim? Communities for a Better Environment (CBE). http://www.cbecal.org/resources/our-research

[40] Palmer et al., Total cost of Ownership and Market Share for Hybrid and Electric Vehicles in the UK, US and Japan. *Applied Energy* 209: 108-119 (2018) (Palmer et al. 2018). www.researchgate.net/publication/321642002_Total_cost_of_ownership_and_market_share_for_hybrid_and_electric_vehicles_in_the_UK_US_and_Japan

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

[42] Community Energy reSource. 2021, *COVID and Oil*. https://www.energy-re-source.com/covid-and-oil

[43] Draft Integrated General Reevaluation Report and Environmental Impact Statement, San Francisco Bay to Stockton, California Navigation Study, April 2019. U.S. Army Corps of Engineers: Jacksonville, FL. *See* p. ES-3, maps. https://usace.contentdm.oclc.org/digital/collection/p16021coll7/id/11171

Finally, Marathon's evident intent to close the Refinery, and the history of chronic under-investment in the Refinery by its multiple owners, must be evaluated in the context of the overall increasingly poor profit margins of crude oil refining. These declining profit margins have led to the closure, and in some cases conversion to biofuels production, of numerous refineries in California and throughout the country. Refinery profits across the nation have been declining since before the COVID pandemic.[44] 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.[45] 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."[46] Specifically in California, growth reversed years ago in both the crude supply and the market that California refineries were first built to tap.[47] The site-specific structural overcapacity that resulted locked in conditions that effectively ended the viability of crude oil processing at the Refinery, as discussed below.

Thus, the Refinery very likely would have closed—with or without the pandemic—because of chronic under-investment in its competitiveness with other refineries that compete for the same dwindling petroleum fuels market. The DEIR should evaluate all of these facts in establishing the baseline from which Project impacts are measured, and in determining the need for mitigation.

2. The DEIR Improperly Concludes Petroleum Processing Will Recommence Without Basing That Conclusion On Any Relevant Evidence.

A conclusion that Marathon has no intention to re-commence crude refining operations at the Refinery is further supported by the fact that it did not, in fact, do so even when refined fuels demand strongly rebounded in 2021 after early-pandemic declines. That fact should have been disclosed and evaluated as part of the DEIR baseline determination, but was not. The DEIR goes to considerable length scrutinizing production levels *before* the pandemic, and then comparing them to 2019-2020 year, during which demand was much lower. DEIR at 3-3 – 6. However, what it fails to consider is the failure of the Refinery to re-commence crude refining operations *after* 2020, in the demand rebound; and the economic factors that underlie that decision.

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[44] "Bad News for Oil: Refinery Profits are Sliding," *Oilprice.com* January 13, 2020, *available at* https://oilprice.com/Energy/Oil-Prices/Bad-News-For-Oil-Refinery-Profits-Are-Sliding.html.

[45] *See* "Factbox: Oil Refiners Shut Plants as Demand Losses May Never Return," *Reuters* November 10, 2020, *available at* https://www.reuters.com/article/us-global-oil-refinery-shutdowns-factbox/factbox-oil-refiners-shut-plants-as-demand-losses-may-never-return-idUSKBN27R0AI; "Refinery News Roundup: Refinery Closures Loom," *Platts S&P Global* November 12, 2020, *available at* https://www.spglobal.com/platts/en/market-insights/latest-news/oil/111220-refinery-news-roundup-refinery-closures-loom-across-the-globe.

[46] "Permanent Oil Refinery Closures Accelerate as Pandemic Bites – IEA," *Reuters* November 12, 2020, *available at* https://www.reuters.com/article/oil-refining-shutdowns/permanent-oil-refinery-closures-accelerate-as-pandemic-bites-iea-idUSL1N2HY13P.

[47] G. Karras, *Decommissioning California Refineries: Climate and Health Paths in an Oil State* at 20, *available at* https://www.energy-re-source.com/decomm (July 2020) and supporting material (Karras 2020).

2021 post-vaccine refined fuels demand has rebounded from unprecedented pandemic lows—at least temporarily—to reach or exceed pre-COVID levels, accounting for seasonal and interannual variability. At the same time, global oil prices are driving price spikes at the pump. The Phillips 66 Rodeo refinery, which is on roughly the same timeline for its proposed biofuel conversion, is currently refining and selling into this apparent bonanza. As the DEIR points out (DEIR at 5-4), the Marathon Martinez refinery has all the permits and equipment in place to do so as well. If Marathon was ever going to restart crude refining at Martinez, it would have done so.

Fuels demand data for California and U.S. West Coast—AK, AZ, CA, HI, OR, and WA; also known as Petroleum Administration Defense District 5 (PADD 5)—are summarized in tables 2 and 3.

Table 2. California Taxable Fuel Sales Data: Return to Pre-COVID Volumes

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

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

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. Data from CDTFA, various years. *Fuel Taxes Statistics & Reports;* California Department of Tax and Fee Administration: Sacramento, CA. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm. *See* Karras, 2021c Attachment 14.

Table 3. 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.

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 2. 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* Table 3.

California and West Coast refineries supplied the rebound in fuels demand while running well below capacity, as summarized in tables 4 and 5.

Table 4. 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 20 March through 6 August 2021 ranged from 81.6% to 87.3% (Table 4), similar to those across the West Coast, and well below maximum West Coast capacity utilization rates for the same months in 2010–2019 (Table 5). Moreover, review of Table 4 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 5. 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 161,000 barrel per calendar day crude capacity of the Refinery.[48] Had the shuttered Refinery restarted, idled capacity elsewhere would have grown to some 383,000–466,000 b/d, a volumetric market impact exceeding the entire capacity of the largest crude refinery in Western North America—the recently consolidated and expanded Marathon Los Angeles refinery (LAR).[49] *See* Table 1. That is, the idled Martinez capacity would have shifted to other refiners in West Coast, and especially the California refining market, including at the LAR. Marathon did not follow this course of action and re-open the Refinery because it would have made no economic sense to do so. The economics that kept the Refinery closed are akin to commercial airline decisions to limit flights to keep seats full. Running refineries closer to empty costs the refiner nearly as much as running closer to full but refinery revenues shrink disproportionately. It became clear in 2021 that the rational economic choice Marathon made was to keep the Refinery closed in order to limit its idled capacity elsewhere. This was the likely reasoning behind the 2020 closure decision, as documented in the previous subsection, and that reasoning did not change with a rebound in demand. The Refinery would almost surely remain closed indefinitely without Project for the same reasons.

The County's failure to consider any of this market data, and to disclose and evaluation the ongoing refinery consolidation driven by structural overcapacity and the first long sustained statewide and West Coast refined fuels demand decline in the recorded history of the oil industry,[50] was inconsistent with CEQA's requirements, and renders the baseline determination unsupported by substantial evidence.

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

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.[51] The Scoping Comments offered reliable data that 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.[52] 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.[53]

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[48] USEIA, 2021.
[49] USEIA, 2021.
[50] USEIA, *Supply and Disposition: West Coast (PADD 5);* U.S. Energy Information Admin-istration: Washington, D.C. www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm.

[51]Scoping Comments, pp. 10.
[52] Scoping Comments, pp. 12-14.
[53] Scoping Comments, pp. 13.

The DEIR effectively disregards all this information. None of the extensive scientific research and data provided by Commenters concerning the potential upstream indirect impact of food crop feedstocks is even referenced, much less considered - even though both the environmental analysis for the California 2017 Scoping Plan and the Low-Carbon Fuel Standard (LCFS) expected localities to disclose, analyze, and mitigate the potentially destructive consequences of such food crop and food system-related biofuels.

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, and no significant impact on land use. DEIR at 3.1-1, 5-10. The DEIR's very limited discussion and conclusions concerning upstream 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 3.8-12 – 15. 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 "expected to include" (DEIR at 2-36; *see* Section II), without describing in detail the full suite of feedstocks the Project could potentially refine, and the factors that will determine the feedstock slate. Further, the analysis makes no reference to the 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.[54]
- *Failure to address impact of feedstock fungibility with an indirect land use change (ILUC) and displacement analysis.* The DEIR nowhere mentions the multiple uses or the fungibility of HEFA feedstocks. There is no mention of the fact that increasing HEFA feedstock demand has induced land conversions or market substitution, ultimately increasing global and domestic agricultural land use changes. Most notably, this includes the increase of overseas palm oil production as domestic soybean oil is diverted from existing uses for biofuel production. [55]
- *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 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

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[54] *Id.*

[55] Scoping Comments at 14. Ironically, the DEIR for the nearby Phillips 66 biofuel conversion project (Phillips 66 DEIR) – deficient in many other ways – does include a discussion of the fungibility of feedstock commodities, entirely omitted in the Marathon DEIR. Rodeo Renewed Project Draft Environmental Impact Report, 2021, Project Description 3-27. https://www.contracosta.ca.gov/DocumentCenter/View/72880/Rodeo-Renewed-Project-DEIR-October-2021-PDF (accessed Dec 7, 2021) (hereinafter Rodeo Renewed Project 2021 DEIR).

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 place caps on the volumes of all feedstocks identified in the DEIR— including SBO and DCO—as a mitigation measure.

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

The DEIR extensively references the California Low Carbon Fuel Standard (LCFS) crediting system, implicitly (albeit not overtly) suggesting that any land use impacts have already been addressed in the environmental analyses to adopt and amend the LCFS.[56] That approach, if the County means to take it, is entirely unsupportable. 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. As the DEIR acknowledges,[57] 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). It 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. [58] DEIR 3.8-13. A closer reading of a key CARB staff report on the LCFS ILUC

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[56] In Section 3.8.12, Greenhouse Gas Emissions Regulatory Setting, the DEIR states, "CARB has previously evaluated, considered and mitigated the environmental impacts associated with increased production and consumption of such fuels at a programmatic level, as part of its adoption, re-adoption and amendment of the LCFS..." DEIR at 3.8-13.

[57] "The LCFS CI [carbon intensity] scoring system therefore reflects CARB's efforts to apply the best available science and economic analyses to mitigate the impacts associated with land use changes occurring both within the U.S. and internationally." DEIR at 3.8-13.

[58] In 2010, the LCFS ILUC analysis updated 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, I-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 for Indirect Land Use Change in Low Carbon Fuel Standard Regulation Staff Report: Initial Statement of Reasons for

analysis clarifies, "The GTAP-BIO analysis was designed to isolate the *incremental* contribution… GTAP-BIO is not predicting the overall aggregate market trend—only the *incremental* contribution of a single factor to that trend… GTAP-BIO projections are *incremental* and *relative*" (emphasis added).[59] 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,[60] disaggregating the land use change estimates by world region and agro-ecological zones (AEZ),[61] and applying annualized emission factors.[62] 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 48,000 b/d—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…"[63] 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."[64] 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.[65] Following the guidance of the 2018 LCFS Final EA, it is up to a project-specific DEIR to analyze the

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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].

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

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

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

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

[63] 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].

[64] *Id.*

[65] *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 [66]

The Project would convert existing crude oil refining equipment for use in HEFA refining. DEIR at 2-19 *et seq*.[67] The only HEFA feedstocks available in commercially relevant amounts for biofuel refining are from land-based food systems.[68] These include the three feedstocks identified in the DEIR: distillers corn oil (DCO), soybean oil (SBO), and tallow or previously-rendered fats. DEIR at 2-36. However, the proposed refinery technology has the ability to process other oil crops not specifically referenced in the DEIR, such as canola, rapeseed, cottonseed oils, tropical palm oil, and used cooking or other previously used "waste" oils which originate mainly from the oil crops and fats.[69] As noted above in Section II, the DEIR states that the Project is "expected to include" the three identified feedstocks, but reflects no commitment to use these feedstocks exclusively, or in any particular proportion.

The law requires more. Even to the extent Marathon 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

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[66] 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).
[67] 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.
[68] 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).
[69] *See* Karras, 2021a and 2021b.

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.

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 market forces will also influence the selection of feedstocks (as acknowledged in the parallel Rodeo Renewed DEIR[70]), 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.[71] 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.[72] 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.[73] 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.[74] 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.

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[70] Rodeo Renewed DEIR 3.8.3.5.

[71] *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).

[72] 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.

[73] *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).

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

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.[75] ILUC is already widely considered in policies to evaluate the environmental benefits of biofuels relative to fossil fuel counterparts, including the California Low-Carbon Fuel Standard, Renewable Fuel Standard (RFS),[76] EU Renewable Energy Directive (RED) and RED II,[77] and ICAO CORSIA[78]. 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. [79] Belgium has already banned soybean oil-based biofuels as of 2022.[80]

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 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,[81] and are incentivized to clear new land to meet increased demand.[82][83]

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[75] *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, 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.)

[76] 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).

[77] 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).

[78] 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).

[79] 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).

[80] 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).

[81] *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].

[82] *Id.*

[83] 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.

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.[84] Due to their fungibility, their prices are 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.[85] Studies have extensively documented the linkage between rising prices for one biofuel feedstock oil crop and the expanding production of another substitute oil crop.[86] These effects have been demonstrated for each of the three feedstocks identified in the DEIR—SBO, DCO, and tallow.

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, the livestock feed market is the primary driver of SBO production, with biofuel demand as an important secondary driver. This means that SBO demand will lead to both *direct* and *indirect* economic pressures to convert domestic and overseas lands for soybean crops.[87] For example, increased biofuel demand is a partial contributor to deforestation in South America for production of soybean crops.[88] Meanwhile, the supply of *palm oil* also responds 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. .[89] [90] The price of SBO, which would be the predominant source

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https://www.transportenvironment.org/wp-content/uploads/2021/08/Biofuels-briefing-072021.pdf (accessed Dec 8, 2021).

[84] The DEIR for the similar Rodeo Renewed biofuel conversion project expressly recognized this fungibility: "The different uses of the commodity and whether or not there are substitutes for those commodities also affect the renewable feedstocks market. For example, soy and corn can both be used for livestock feed or human food production. If one commodity increases in price, farmers may be able to switch to the other commodity to feed their livestock for a cheaper cost (CME Group). This is particularly important for renewable feedstocks given the different uses for oilseeds, including food production and animal feedstocks, and the different vegetable oils that may be used as substitutes (e.g., canola oil may be a substitute for soybean oil)." Rodeo Renewed DEIR 3.8.3.2.

[85] *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).

[86] *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).

[87] 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).

[88] 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

[89] *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).

[90] 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).

of feedstock in this Project, is already skyrocketing, in part in connection with increased biofuel production.[91] Marathon has ostensibly recognized the unacceptable environmental destruction associated with palm oil production, also described in subsection E, in its commitment not to use palm oil. However, by proposing a Project that will heavily rely on SBO, palm oil production and use will nonetheless increase because of SBO 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).[92] DCO can be extracted from distiller's grains with solubles (DGS), leading to substitution effects between the two commodities.[93] 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.[94] 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.[95] 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.[96] 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.[97]

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.[98] 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,

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[91] *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).

[92] 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).

[93] *Id*. at 79.

[94] 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).

[95] *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).

[96] Searle 2019.

[97] 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).

[98] 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).

soaps, and cosmetics.[99] 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.[100]

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 Marathon, given its potential to significantly disrupt food crop agricultural patterns.

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.[101] 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 Rodeo Renewed, *see* Section VIII) 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 48,000 b/d[102] of lipid feedstocks 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.[103] The Project would increase this nationwide total by a full 42 percent.[104]

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.[105]

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[99] Baldino, Searle, and Zhou, 2020-25, pp. 6.
[100] Pavlenko and Searle 2020-22, pp. 26.
[101] *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).
[102] DEIR 2-2.
[103] 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).
[104] DEIR 2-2. The Project percentage boost over existing biofuel feedstock consumption is from 48,000 b/d, divided by that 113,000 b/d from existing biodiesel production.
[105] 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,

Thus, the Project alone would consume approximately a 13 percent share[106] 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 43 percent of total U.S. farm yield for *all* uses of these oils and fats. The Project alone would thus commit a disproportionate share of US food crop oils to California, with attendant potential climate consequences.[107]

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.[108] As a result, the Project alone could use up to 24 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 LCFS environmental assessment it cited, 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 / 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

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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.

106 This figure represents Project feedstock demand of 48,000 b/d over the estimated 372,000 b/d total lipid production in the U.S. calculated in the previous footnote.

107 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 13% of that total U.S. yield (for all uses) to biofuels produced at the Refinery alone.

108 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.

majority of this land use change would be overseas, with 1.2 million acres of the converted land use outside of the U.S.[109] 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 0.74 billion gallons of feedstock consumed by the Project and if 100% of that feedstock was SBO, would mean 1.8 million acres of land would need to be converted for this Project.

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.[110] 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.[111] 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.[112]

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

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109 2018 CARB LCFS Staff Report Appendix I-8, I-29, I-30.

110 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).

111 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);.

112 CARB 2018 LCFS Final EA, pp. 120, 172-173.

result from farming and ranching may include sediment, nutrients, pathogens, pesticides, metals, and salts; increased use of pesticides could increase greenhouse gas emissions.[113]

The expansion of palm oil production, due to SBO consumption as described above, will have a particularly severe environmental impact.[114] The palm oil industry is a source of pollutants and greenhouse gas emissions in two ways: deforestation and the processing of palm 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 biofuels are dangerous for terrestrial and aquatic ecosystems.[115] Palm oil production happens in biodiversity hotspots like Indonesia and the Brazilian Amazon, where massive deforestation and attendant species loss can dramatically affect both global biodiversity and the climate.[116]

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.[117] 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."[118] More than 90% of emissions from grassland conversions came from soil organic carbon stocks (SOC).[119] Due to the longtime accumulation time of the SOCs, those emissions may be impossible to mitigate on a time scale relevant to humans.[120.]

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

[114] *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);.

[115] *Id.,* pp. 7-11.

[116] *Id.*

[117] Malins 2019, pp. 5.

[118] 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).

[119] Spawn 2019, pp. 5.

[120] Spawn 2019, pp. 7, 9.

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.[121] As a result, modeled soy-based biofuel net carbon emissions are , at best, virtually the same as those from fossil diesel, with even worse climate impacts for greater quantities of soy-based biofuel produced.[122] 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.[123] The one mitigating measure it did mention, best management practices (BMPs), has no meaningful application here.

Best Management Practices: Section 6.2 of the DEIR, concerning significant irreversible environmental changes, contains a brief high-level mention of Best Management Practices (BMPs) that can reduce agricultural impacts when used properly. DEIR at 6-3 *et seq.* However, the DEIR nowhere proposes BMPs as a mitigation measure. Indeed, without further specificity about the type and origins of potential feedstock, it is also impossible to know what types of BMPs are possible.

BMPs should, however, have been specifically 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. [124]

Feedstock Cap: To guard against the severe environmental and climate 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, as already recommended by environmental advocates for California climate policy.[125] The DEIR should have considered

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[121] 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.
[122] Malins 2020a, pp. 57.
[123] *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.
[124] *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.
[125] *See e.g.,* Martin et al., Union of Concerned Scientists Letter Re: 2022 Scoping Plan - Scenario Inputs Technical Workshop, Nov 10, 2021, pp. 3 ("_...CARB should ensure that future growth comes primarily from [non-lipid]

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.[126]

V. THE DEIR FAILS TO ASSESS AND MITIGATE PROCESS SAFETY RISKS ASSOCIATED WITH RUNNING BIOFUEL FEEDSTOCKS[127]

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.

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.[128]

The reason for the increased heat, and hence risk, is that the removal of oxygen from 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.[129] Reacting more hydrogen

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feedstocks and directly constrain the consumption of lipid-based fuels at a level commensurate to the available feedstocks. In addition to an immediate constraint on the scale of lipid diversion to fuel markets, CARB should monitor the use of corn grain, various categories of biomass, electricity and hydrogen and ensure the scale of their use for fuel, energy or carbon removal uses does not exceed a sustainable level.")

[126] 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 (accessed Dec 12, 2021).

[127] 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."

[128] 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.

[129] The Project could consume 2,220–3,020 standard cubic feet of H_2 per barrel of biomass 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.

over the catalyst in the hydrotreating or hydrocracking reactor generates more heat faster.[130] This is a well-known hazard in petroleum processing, that manifests frequently in flaring hazards[131] when the contents of high-pressure reactor vessels must be depressurized[132] 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.[133]

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 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 one researcher 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.[134]

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 49 hydrogen-related process safety hazard incidents occurred at the Refinery from January

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[130] 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.
[131] 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.
[132] 22 Chan, E., 2020. Converting a Petroleum Diesel Refinery for Renewable Diesel; White Paper /- Renewable Diesel. Burns McDonnell. www.burnsmcd.com/insightsnews/tech/converting-petroleum-refinery-for-renewable-diesel. (Chan, 2020) *See* p. 2 ("emergency depressurization" capacity required).
[133] van Dyk et al., 2019 ("heat release proportional to the consumption of hydrogen"); and Chan, 2020 at 2 ("significantly more exothermic than petroleum diesel desulfurization reactions").
[134] Chan, 2020.

2010 until it closed on 28 April 2020.[135] 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 77 days. Considering both the Refinery and the Phillips 66 rodeo facility data together during this period, sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these reported incidents.[136] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[137] 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 three of these incidents, consequences of underlying hazards included fires at the Refinery.[138]

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

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire;[139]
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage;[140]
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor;[141]
- A 2015 hydrogen conduit explosion throws workers against a refinery structure;[142]
- 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;[143]
- 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;[144]
- 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 this Refinery;[145]

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[135] 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.
[136] Flaring causal analyses as cited above. Hydro-conversion includes hydrotreating and hydrocracking.
[137] *Id.*
[138] Flaring causal analyses as cited above. *See* reports for incidents starting 13 May 2010, 17 February 2011 and 17 April 2015.
[139] Process Safety Integrity, *Refining incidents;* https://processsafetyintegrity.com/incidents/industry/refining ; *see* Bayernoil Refinery Explosion, January 2018.
[140] Process Safety Integrity as cited above; *see* Syncrude Fort McMurray Refinery Fire, March 2017.
[141] Process Safety Integrity as cited above; *see* Sir Refinery Fire, January 2017.
[142] Process Safety Integrity as cited above; *see* Petrobras (RLAM) Explosion, January 2015.
[143] Process Safety Integrity as cited above; *see* BP Texas City Refinery Explosion, March 2005.
[144] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Explosion, March 1999.
[145] Process Safety Integrity as cited above; *see* Tosco Avon (Hydrocracker) Explosion, January 1997.

- 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;[146]
- 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;[147]
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.[148]

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 – *see* Section VII).

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 they 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,"[149] the least effective type of safety measure in the "Hierarchy of Hazard Control"[150] set forth in California process safety management policy for petroleum refineries.[151] Marathon itself added automated

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[146] Process Safety Integrity as cited above; *see* Carson Refinery Explosion, October 1992.
[147] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Fire, April 1989.
[148] Process Safety Integrity as cited above; *see* BP (Grangemouth) Hydrocracker Explosion, March 1987.
[149] 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).
[150] 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).
[151] 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.

shutdown control logic systems to these procedural safeguards before it closed the refinery, but these are "active safeguards,"[152] the next least effect type of safety measure in the Hierarchy of Hazard Control. Marathon now proposes 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,"[153] the next least effective type of measure in the Hierarchy of Hazard Control, after procedural and active safeguards. Marathon has not proposed more effective first or second order inherent safety measures for the specific Project hazards identified above.

Importantly, and perhaps most telling, Marathon proposes to repurpose and continue to use the flare system of its closed refinery for this Project. DEIR at 2-22. 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.[154] This is a procedural safeguard, again the least effective type of safety measure.[155] 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.

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.

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[152] 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).
[153] See CCR § 5189.1 (c).
[154] *See* BAAQMD regulations, § 12-12-301. Bay Area Air Quality Management District: San Francisco, CA.
[155] *See* Procedural Measure and Hierarchy of Hazard Control definitions under CCR § 5189.1 (c) in the notes above.

- *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.

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[156]; 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."[157] 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

[156] 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.
[157] *See* https://dieselfree33.baaqmd.gov/ (landing page), https://dieselfree33.baaqmd.gov/statement-of-purpose (text of the pledge), https://dieselfree33.baaqmd.gov/signatories (signatories).

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.

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 6), 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 Marathon 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 6. Impact of Project Feedstock Choice on CO_2 Emissions from Hydrogen Production for Marathon 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]	855,000	1,020,000	1,110,000	165,000	255,000
Methane feed (t/y) [b]	797,000	954,000	1,040,000	157,000	243,000

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 48,000 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[158] 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 6 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 Marathon 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

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

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.[159]

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 6 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 H_2/barrel). Table 6. Similarly, the 1.48 kg/b difference between saturating 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 Marathon runs SBO, Project hydrogen plants could emit approximately 165,000 metric tons more CO_2 each year than if it runs tallow. *Id.* This 165,000 t/y excess would exceed the emissions significance threshold for greenhouse gases in the DEIR, 10,000 metric tons/year CO_2e (DEIR at 3.8-16) by *15 times.* And if Marathon were to run fish oil, another potential feedstock not specifically targeted but also not excluded, the estimates in Table 6 suggest that Project hydrogen plants could emit 255,000 tons/year more CO_2 than if it runs tallow, or *24 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 6 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

[159] 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.

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,[160] the tendency of older plant designs to be less efficient and higher-emitting, and since the Marathon No. 1 Hydrogen Plant design is a 1963 vintage.[161] The DEIR should have evaluated this part of Project processing emissions using data for the Marathon and Air Products hydrogen plants that would be used by the Project; and Marathon 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.[162]

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. It is relevant because, although Marathon originally said that the project would target drop-in biodiesel, it could switch to target jet fuel production. Indeed, Marathon hinted recently that it may do so.[163] Available evidence suggests that targeting jet fuel instead of drop-in diesel production from the same vegetable oil or animal fat feed could increase processing emissions significantly.[164] 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.

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[160] 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 .

[161] BAAQMD Source S-1005. *See* Application 28789 File, submitted to the Bay Area Air Quality Management District (BAAQMD) by Tosco Corp. on 9 Sep 1982 for permits regarding this refinery now owned by Marathon. *See* esp. Form G for Source S-1005 as submitted by M. M. De Leon, Tosco Corp., on 11/12/82.

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

[163] Compare January 29, 2021 draft Project Description at 1-1 ("including renewable diesel, renewable propane, renewable naphtha, *and potentially renewable jet*") (emphasis added) with October 2020 Project Description at 1-1 ("including renewable diesel, renewable propane, and renewable naphtha"). We note in this regard that as stated in its title, the preliminary estimates in Table 2 are based on the conversion of Project feedstocks into diesel, not jet fuel. Emissions from jet fuel production could be significantly higher.

[164] 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.

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;[165] and SB32, which calls for reductions in GHG emissions to 40% below 1990 levels by 2030.[166] Following this, California Executive Order S-3-05 calls for a reduction in GHG emissions to 80% below 1990 levels by 2050.[167] 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."[168]

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;[169] 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 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.[170] 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-

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[165] 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

[166] 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

[167] 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.

[168] 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.

[169] 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

[170] 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. .

barrel impacts, is not set up to address the macro impact of overproduction 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),[171] Air Resources Board (CARB)[172] and Public Utilities Commission,[173] Austin et al. for the University of California,[174] 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.[175] Their work evaluates a range of paths to state climate goals,[176] analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,[177] and addresses potential biomass fuel chain effects on climate pathways.[178]

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[171] 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

[172] 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.

[173] 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

[174] 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

[175] 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.

[176] Mahone et al. 2020a.

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

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

Mahone's study prepared for CARB explored three scenarios for achieving carbon neutrality by 2045.[179] 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 1 illustrates the transportation fuel mix for these three pathways:

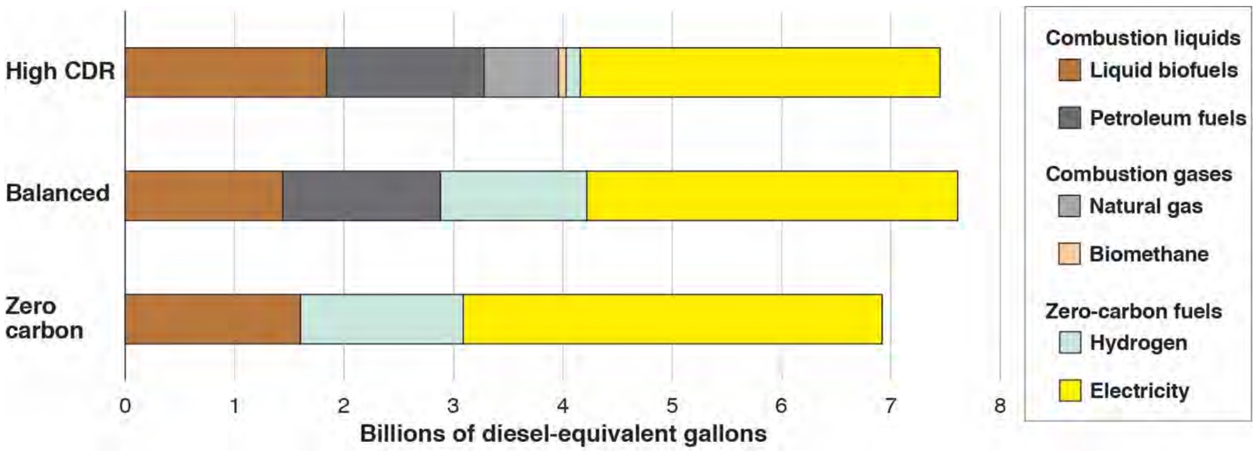

Chart 1: California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.
Adapted from Figure 8 in Mahone et al. (2020).[180] Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).

Total liquid hydrocarbon combustion fuels for transportation in 2045, including 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.[181] 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 put limits on the use of biofuels by specifically excluding or limiting the production of HEFA ("lipid") fuels. PATHWAYS, the primary

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[179] 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 .
[180] Mahone et al., 2020.
[181] Mahone et al., 2020.

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.[182] Mahone et al. chose to exclude purpose-grown crops, as explained in prior similar studies, 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.[183] 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.[184] Yet new in-state HEFA distillate (diesel and jet fuel) production proposed statewide, with a large share to come from the Martinez Refinery, would total approximately 2.1 billion gallons/year when fully operational.[185] If fully implemented, HEFA 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

[182] 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.

[183] *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)

[184] 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

[185] 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.

intensity of refining at the average U.S. crude refinery.[186] 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 goal of emissions 80% below 1990 levels by 2050[187] 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. [188] Adding in emissions from remaining petroleum fuel production could push emissions to 91 Mt in 2050.[189] Total 2050 emissions would 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.[190] Therefore, repurposing idled petroleum refinery assets for HEFA biofuels will cause us to miss key state climate benchmarks.

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 biofuel production 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

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[186] 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 Marathon: among HEFA feeds, and between diesel versus jet fuel production targets. Karras, 2021a.
[187] 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.
[188] 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.
[189] *Id.*
[190] 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.

burned elsewhere, causing a worldwide net increase in GHG emissions. The DEIR improperly concludes the project would decrease net GHG emissions[191] 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 That 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."[192] 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[193] and total distillates—petroleum distillates and diesel biofuels—burned in California.[194] 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 2, 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 since 2012 - originally expected to replace fossil fuels - actually merely added a new source of carbon to the global 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.[195] [196]

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.

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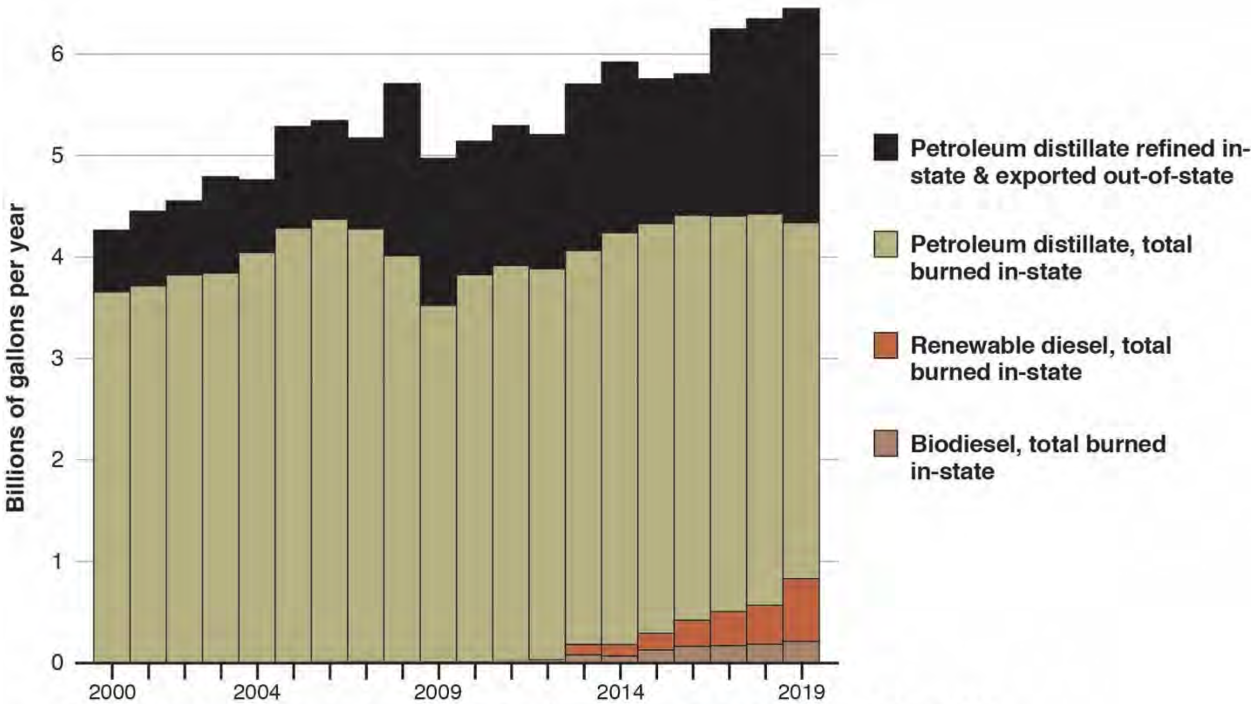
191 "Project would result in an overall decrease in emissions ... [including] indirect GHG emissions" (DEIR p. 3.8-20) and "GHG emissions from stationary and mobile sources" DEIR at 3.8-22.
192 CCR §§ 38505 (j), 38562 (b) (8).
193 CEC Fuel Watch data, various dates.
194 CARB GHG Inventory Fuel Activity data, 2019 update.
195 *Id.*
196 CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php



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 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 describes potential GHG emissions resulting from imports[197] while ignoring fuels exports from California 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 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.[198] 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 2. California refining capacity, especially, is overbuilt.[199] 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

[197] DEIR p. 4-12
[198] USEAI, 2015.
[199] Karras, 2020. *Decommissioning California Refineries.*

statewide refinery production to other states and nations from 2013–2017.[200] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[201] *See* Table 7.

Table 7. 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.

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

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 GHG 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 8.

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

Table 8. 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	Marathon Project	Phillips 66 Project	Both Projects
Fuel Shift (millions of gallons per day) [a]			
RD for in-state use	1.623	1.860	3.482
PD equivalent exported	1.623	1.860	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	3.46	3.96	7.42
RD from crop biomass feedstock	4.99	5.72	10.7
PD (petroleum distillate)	8.00	9.17	17.2
Net emission shift impact [d]			
Annual minimum (Mt/year)	3.46	3.96	7.42
Annual maximum (Mt/year)	4.99	5.72	10.7
Ten-year minimum (Mt)	34.6	39.6	74.2
Ten-year maximum (Mt)	49.9	57.2	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 Rodeo project calculated at 55,000 b/d feed rate, less than the 80,000 b/d Rodeo project capacity.

Accounting for fuel yields on refining targeting renewable diesel[202] and typical feed and fuel densities shown noted in Table 8, at its 48,000 b/d capacity the project could produce approximately 1.62 million gallons per day of renewable diesel, potentially resulting in crude 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[203] 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 3.46 to 4.99 million metric tons (Mt) of CO_2e emitted per year. Table 8. Those potential Project emissions would exceed the 10,000 metric tons per year (0.01 Mt/year) significance threshold in the DEIR by 345 to 498 *times*.

[202] Pearlson et al., 2013.
[203] Low Carbon Fuel Standard Regulation, CCR §§ 95484–95488, tables 2, 4, 7-1, 8 and 9.

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 "[t]he Project would result in emission reductions of all criteria air pollutants from both stationary and mobile sources" (DEIR at 3.3-38) 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- the first of which was addressed extensively in the Scoping Comments but ignored by the County. 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 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[204]

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

1. <u>The DEIR Did Not Describe the Air Quality Impacts of Flaring</u>

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 analysissince, as discussed in Section V, the Project is likely to increase process upset incidents at the Refinery.

[204] 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."

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. [205]

2. <u>The DEIR Failed to Describe the Impact of Feedstock Switching on Flaring</u>

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.[206] Had the DEIR evaluated the same

[205] Karras, 2021a.
[206] Karras, 2021a.

data source,[207] [208] 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.[209] [210] 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."[211]

3. <u>The DEIR Fails to Evaluate the Likelihood of Increased Flaring</u>

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 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.[212] Here in the Bay Area, preventable refinery flaring is an unpermitted activity that contravenes air

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[207] BAAQMD Regulation 12-12-406 Causal Reports; reports relevant to the Project accompany this Comment; recent reports available at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports

[208] BAAQMD Regulation 12 Rule 12. Bay Area Air Quality Management District Regulation 12, Miscellaneous Standards of Performance, Rule 12. BAAQMD: San Francisco, CA. Amended 3 November 2021.

[209] van Dyk et al., 2019.

[210] Chan, 2020.

[211] Karras, 2021a.

[212] 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.

quality policy and law.[213] 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;[214]
- 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;[215] 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 from consideration. Overwhelming evidence based on scientific data, information, and the long history of environmental, toxicological, and environmental justice experience and practice demonstrate the necessity to address acute as well as chronic and local as well as regional exposures to air pollutants. For example, the facility air permit itself specifies hourly and daily as well as annual emission limits.[216] Yet throughout the DEIR it erroneously conflates these acute and chronic exposure impacts, drawing numerous conclusions that facility emission impacts of the Project are "beneficial" or "less than significant" based on average rates of emission from continuous sources alone.

Potential air quality impacts associated with acute exposures to short-term episodic emissions from the refining facilities are systematically excluded from DEIR consideration.[217] The DEIR fails to evaluate or address episodic emissions from flaring, as discussed directly above in subsection B. The DEIR Health Risk Analysis (HRA) is based solely on average long-term exposure data. Additionally, 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

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[213] BAAQMD Regulation 12, Rule 12.
[214] Karras, 2021a.
[215] Karras, 2021a.
[216] Major Facility Review Permit Issued To: Tesoro Refining & Marketing Company LLC, Facility #B2758 & Facility #B2759; Jan. 11, 2016.
[217] Karras, 2021c

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. 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.[218]

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;[219]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.[220] 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 an 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

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. DEIR at 3.3-41. 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 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 would be eliminated in the context of an open-plan petroleum refinery surrounded by

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[218] Karras, 2021c.
[219] Karras, 2021a.
[220] Karras, 2021a.

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. These could, in principle, 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 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. Third, while the analysis appropriately includes an electrolytic hydrogen alternative, the analysis of that alternative omits important criteria that should have been considered.

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 resume, continuing crude oil processing operations indefinitely at historic levels. DEIR at 5-4. Yet the document provides no evidence whatsoever 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 Marathon has no plans to restart crude oil processing at the Refinery if its application to convert to biofuel production is denied. It is imperative, to ensure a rational alternatives analysis, that the County include a no project alternative that is grounded in reality.

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. 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 Alternatives Analysis Artificially Separates Alternatives that are Not Mutually Exclusive

In addition to the (inappropriately characterized) no project alternative, the DEIR considered two additional alternatives in addition to the Project: the "reduced renewable feedstock throughput" alternative and the "green hydrogen" alternative. DEIR at 5-4 – 5. These alternatives were appropriate for consideration, as both are feasible means to reduce Project impacts. However, the DEIR presents no reason why these two alternatives were evaluated as separate options rather than collectively. Nothing about them is mutually exclusive: electrolytic "green" hydrogen could supply a refinery with reduced throughput in the same way it could supply the Project. Nothing in the DEIR suggests to the contrary. Indeed, to the extent the scale of required electrolytic hydrogen may be a concern – e.g., with respect to the reference in the DEIR concerning the Refinery's footprint with the addition of solar panels – implementing the two alternatives together would mitigate that concern. The DEIR should therefore have either considered the two non-project alternatives collectively in addition to separately, or else provided sufficient evidence and reasoning as to why this combined approach would not be feasible.

C. The Analysis of the Green Hydrogen Alternative Fails to Consider Essential Information Concerning its Benefits

Commentors raised in the Scoping Comments the need for reasonable analysis of renewable powered electrolytic zero emission hydrogen (ZEH) . The DEIR acknowledges that ZEH is feasible.

However, the DEIR did not present a reasonable analysis ZEH. Its analysis was unreasonbly biased by a combination of overly narrow interpretation of Project objectives, incomplete description of ZEH, and failure to consider significant impacts ZEH could lessen or avoid. The DEIR states that alternatives were considered based on three criteria (in addition to the no project alternative requirement): achievement of Project goals, lessening of impacts, and feasibility. While these criteria were not inappropriate, the analysis was skewed and deficient in several ways, all potentially to the detriment of fair consideration of the green hydrogen alternative. Indeed, it is clear from information the County has provided to Commenters that its site-specific analysis of the feasibility of the green hydrogen alternative was exceedingly limited.[221]

These flaws are significant. The Project's fossil gas "gray" hydrogen production that ZEH could replace will emit roughly one million metric tons of carbon dioxide annually. Failing to consider elimating that million annual tons as mitigation for significant Project GHG impacts is not a reasonable DEIR analysis.

1. <u>Overly Narrow Interpretation of Project Objectives</u>

First, the Project objectives are drawn in an overly narrow fashion that may unfairly bias consideration of the green hydrogen alternative (as well as alternative technologies more generally, per Section II). The list of Project objectives in the DEIR twice references a goal of "repurposing" Refinery infrastructure. DEIR at 1-1. 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 Marathon 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. [222]

2. <u>The DEIR's Incomplete description of ZEH Skewed DEIR Environmental Analysis</u>

The DEIR concludes without sufficient basis that ZEH would result in certain impacts to a greater extent than the Project or other alternatives due to an increased onsite solar generation footprint. However this unsupported impact conclusion assumed onsite solar power would be the only source electricity for splitting water to create zero emission hydrogen, This impact conclusion relied on the size of the onsite solar footprint. But that was false reliance. Despite abundant well documented evidence that grid-supported as well as onsite power is a standard

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[221] Commenter NRDC submitted a Public Records Act request to the County for "Records concerning electrolysis or "green" hydrogen at the Marathon/Tesoro Martinez refinery in connection with the DEIR for the Renewable Fuels Project, County File No. CDKP20-02046, SCH No. 2021020289." Letter dated November 9, 2021 from Ann Alexander to Lauwrence Huang. In response, via the email from Lawrence Huang to Ann Alexander also dated November 9, 2021, the County provided only a single one-paragraph document from Marathon concerning the site-specific aspects of an electrolytic hydrogen alternative.

[222] Moreover, if ZEH were used, the hydrogen contained in project-produced "renewable" fuels would be renewable, such that that ZEH would better achieve the renewable fuels production project objective.e.<u>*See*</u> Karras, 2021a.

option for ZEH* neither grid-only nor grid-plus-onsite power was disclosed or evaluated in the DEIR, further skewing its analysis.

3. The DEIR Fails to Consider Significant Project Impacts ZEH Could Lessen or Avoid

The DEIR analysis fails to sufficiently consider the ways in which ZEH would mitigate the Project's significant climate impacts - identified in this Comment, but not the DEIR, per Sections II and VIAs discussed in those sections, while the DEIR determines the Project's GHG impacts to be non-significant, DEIR at 3.8-21, that determination was incorrect – both due to the inappropriately inflated Project baseline as described in Section II, and the DEIR's failure to account for the hydrogen intensity and emission-shifting impacts of biofuel production, as described in Section VI.

As discussed in Section VI, California's climate policy includes a commitment to zero-emission transportationConstruction of ZEH at the Project site could be critical for achieving this goal, to the extent it sets of the possibility of re-purposing the ZEH in the future for direct transportation use once the commercial life of the repurposed Refinery ends in the reasonably foreseeable future (*see* Section II). Fuel cell electric vehicles (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. 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[i] 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]

Additionally, the ability of ZEH technology to utilize peak solar and wind power and store that zero emission energy as hydrogen, enabling its return to grid at night and, perhaps more importantly, during longer calm periods of reduced wind resource power, may give ZEH a crucial role in the array of "grid balancing" measures essential to fully decarbonizing electricity.[223]

ZEH is thus critical to achieving the vehicle electrification goal, because it can fuel FCEVs without the carbon footprint of the fossil gas steam methane reforming hydrogen currently used at the Refinery, and can additionally help support the growth of renewable power for both battery and fuel cell electric vehicles growth. If ZEH has been constructed as part of the Project, that infrastructure would be poised to transition to facilitating the deployment of FCEVs contemplated by California's climate pathways. However, if the Refinery's existing hydrogen infrastructure has been repurposed for the Project and hence locked in, that infrastructure will be unable to support California's zero-carbon transportation goals.

4. The ZEH Analysis Should Have Considered Economic and Social Benefit

The DEIR does not consider the net costs (costs minus benefits) for the ZEH. In view of the very high GHG emissions and other air pollution from the legacy gray hydrogen facility, the

[223] *See* Karras, 2021a.

mitigation is 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.[224] 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.

Thus, the DEIR should have not only found the GHG impacts from the Project to be significant in view of the analysis in Sections II and VI above, but specifically taken into consideration the ability of the green hydrogen alternative to mitigate that impact.

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 2 miles of the Project site or the associated marine oil terminals. 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 2-mile radius are random and highly disparate, most being radically different in type from the Project and having few if any correlative impacts. These

[224] 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.

“cumulative” projects include, *inter alia,* a wetlands restoration project, a housing development, conversion of a billboard to digital format, and a self-storage unit development. DEIR at 4-3 – 7.

The very similar Phillips 66 Rodeo biofuel conversion project, lost in this strange mix, receives barely a mention in the analysis. The Rodeo project is referenced and described in a single paragraph, but “discussion” of its cumulative impacts consists of exactly two passing sentences: one referencing its purported reduction in emissions (a false conclusion, for reasons addressed in the comments being submitted by Commenters on that project’s DEIR showing similar issues with a faulty baseline) (DEIR 4-8); and the other referencing, entirely non-quantitatively, the cumulative impact of the two projects on marine impacts. DEIR at 4-10.

This approach is deficient in multiple respects. First, the DEIR failed to specify a rational basis for the universe of projects considered in the cumulative impacts analysis – with respect to either the 2 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 Phillips 66 Rodeo 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 Phillips 66 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 biofuel projects currently under construction and proposed in

California, such as the AltAir Paramount[225] and Alon Bakersfield[226] 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 VI.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 42 percent (48,000 b/d). The Project could in principle, standing alone, consume up to 24 percent of the total U.S. supply of soybean oil production for all uses.

The larger 80,000 barrel per day Phillips 66 conversion project would have an even greater impact on feedstock consumption levels, and hence on agricultural resources and their availability. As Commenters described in separate comments concerning the DEIR for that project,[227] the Rodeo project could increase demand for feedstock oils itself by 71% and could alone consume up to 39 percent of the nation's total supply of soybean oil. Yet the overall limitation on HEFA feedstock availability is well documented within the scientific community,[228] the financial industry,[229] the environmental justice community,[230] as well as

[225] *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.

[226] 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).

[227] Comments by Biofuelwatch et al dated December 17, 2021 concerning Rodeo Renewed project.

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

[229] 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).

[230] *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.

within the biofuel industry[231] 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."[232] 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 10, as of fall 2021, there are eight operating renewable biofuel facilities and 75 biodiesel facilities, with a combined potential capacity 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 9.

[231] 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.
[232] 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 9: 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,[233] 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.

[233] *See also* findings by EIA that by 2024, U.S. renewable diesel production could total 5.1 billion gal/yr (330,000 b/d) from all projects either under construction, proposed, or announced. Note that this total does not include existing or future lipid-consuming biodiesel projects. Hill et al., U.S. renewable diesel capacity could increase due to announced and developing projects, July 29, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48916 (accessed Dec. 13, 2021).

Table 10: 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 Yield (%)
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/ (accessed Dec. 14, 2021).; EIA, U.S. Biodiesel Plant Production Capacity, Petroleum Reports, September 3, 2021, https://www.eia.gov/biofuels/biodiesel/capacity/ (accessed Dec. 14, 2021). **a.** Frohlke, U. Haldor Topsoe HydroFlex technology results in successful test run at Marathon Petroleum Corp facility producing 100% renewable diesel, Haldor Topsoe, Aug 5. 2021, https://blog.topsoe.com/marathon-petroleum-corporation-confirms-successful-test-run-for-us-refinery-producing-100-renewable-diesel-based-on-topsoes-hydroflex-technology (accessed Dec 14, 2021). **b.** Viking Energy Group, Inc. Viking Energy Signs Agreement to Acquire Renewable Diesel Facility, Globe Newswire, Dec. 1, 2021, ttps://www.globenewswire.com/news-release/2021/12/01/2344429/0/en/Viking-Energy-Signs-Agreement-to-Acquire-Renewable-Diesel-Facility.html (accessed Dec 14, 2021). **c.** Cox, J. Refinery on Rosedale makes final changes for switch to cleaner fuel, Bakersfield.com, Nov. 6, 2021, https://www.bakersfield.com/news/refinery-on-rosedale-makes-final-changes-for-switch-to-cleaner-fuel/article_36271b12-3e94-11ec-b8ac-df50c6c90b95.html (accessed Dec 14, 2021). **d.** Brelsford, R. HollyFrontier lets contract for new unit at Navajo refinery, Oil & Gas Journal, Jan. 29, 2020, https://www.ogj.com/refining-processing/refining/article/14092707/hollyfrontier-lets-contract-for-new-unit-at-navajo-refinery (accessed Dec 14, 2021). **e.** McGurty, J. HollyFrontier increases renewable fuel capacity with purchase of Sinclair Oil, S&P Global, Aug. 3, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/agriculture/080321-hollyfrontier-increases-renewable-fuel-capacity-with-purchase-of-sinclair-oil (accessed Dec. 14, 2021). **f.** McGurty, J. Diamond Green Diesel St. Charles renewable diesel expansion starting up, S&P Global, Oct. 21, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/agriculture/102121-refinery-news-diamond-green-diesel-st-charles-renewable-diesel-expansion-starting-up (accessed Dec. 14, 2021). **g.** McGurty, J. Diamond Green Diesel St. Charles, Louisiana, renewable diesel plant shut ahead of Ida, S&P Global, Aug 29, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/oil/082921-diamond-green-diesel-st-charles-louisiana-rd-plant-shut-ahead-of-ida (accessed Dec. 14, 2021). **h.** Brelsford, CVR Energy lets contract for Wynnewood refinery renewables project, Oil & Gas Journal, Jan. 27, 2021, https://www.ogj.com/refining-processing/refining/operations/article/14196317/cvr-energy-lets-contract-for-wynnewood-refinery-renewables-project (accessed Dec. 14, 2021). **i.** Ryze Renewables, Renewable Diesel Facilities in Reno and Last Vegas, https://www.ryzerenewables.com/facilities.html (accessed Dec. 14. 2021). **j.** Erfid, C. NEXT Renewable Fuels Oregon EFSC Exemption Request. Letter to Todd Cornett, pp. 2, Oct. 30, 2020, https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2020-11-9-PWB-Request-for-Exemption.pdf (accessed Dec. 14, 2021). **k.** Voegele, E. REG discusses Geismar expansion, Houston shutdown in Q3 results, Biodiesel Magazine, Nov. 8, 2021, http://www.biodieselmagazine.com/articles/2517837/reg-discusses-geismar-expansion-houston-shutdown-in-q3-results (accessed Dec. 14, 2021). **l.** City of Paramount, Notice of Preparation of a Draft Subsequent Environmental Impact Report, Paramount Petroleum AltAir Renewable Fuels Project, CUP 757 Amendment, pp. 12, Jun. 4, 2020, https://www.paramountcity.com/home/showpublisheddocument/5764/637268681923030000 (accessed Dec. 14, 2021). **m.** Boone, T., Grön Fuels gets air quality permit for proposed $9.2 billion plant, The Advocate, Apr. 22, 2021, https://www.theadvocate.com/baton_rouge/news/business/article_9e4a0144-a378-11eb-bc32-6362f7d3744c.html (accessed Dec. 14, 2021). **n.** Brelsford, R. PBF Energy advances plans for proposed Chalmette refinery renewables project, Oil & Gas Journal, Aug. 6, 2021, https://www.ogj.com/refining-processing/refining/article/14208235/pbf-energy-advance-plans-for-proposed-chalmette-refinery-renewables-project (accessed Dec. 14, 2021). **o.** Brelsford, R. Calmut lets contract for Montana refinery's renewable diesel project, Oil & Gas Journal, Aug. 31, 2021, https://www.ogj.com/refining-processing/refining/article/14209547/calumet-lets-contract-for-montana-refinerys-renewable-diesel-project (accessed Dec. 14, 2021). **p.** Brelsford, R. Seaboard Energy lets contract for Kansas renewable diesel plant, Oil & Gas Journal, May 14, 2021, https://www.ogj.com/refining-processing/refining/article/14203325/seaboard-energy-lets-contract-for-kansas-renewable-diesel-plant (accessed Dec. 14, 2021). **q.** McGurty, J. Chevron expands renewable fuels output with more lower carbon business spending, S&P Global, Sep. 14, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/agriculture/091421-chevron-expands-renewable-fuels-output-with-more-lower-carbon-business-spending (accessed Dec. 14, 2021). **r.** CVR Energy selects Honeywell technology for Coffeyville refinery, Dec. 9, 2021, http://biomassmagazine.com/articles/18550/cvr-energy-selects-honeywell-technology-for-coffeyville-refinery (accessed Dec 14, 2021). **s.** Rodeo Renewed DEIR at 3-23 **t.** Marathon Martinez DEIR at 2-15 **u.** Feedstock capacities calculated assuming a feed-to-product mass ratio of 80.9% per Pearlson et al. (2013) for maximum distillate production, an average lipid feedstock specific gravity of 0.916 (that of soybean oil), and an average product specific gravity of 0.78 (that of renewable diesel). **v.** Total US yield of lipids taken from Table 9.

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

B. The DEIR Should Have Analyzed the Cumulative Impact of California Biofuel Production on the State's Climate Goals[234]

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.

Within the fuel market, "renewable" diesel production targeting the California fuels market has already been growing at an increasingly rapid rate since 2011.[235] Growing by a factor of 65 times to 2.79 million barrels per year (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/ya as of the end of 2019.[236] Planned new HEFA capacity targeting the California fuels market and planned for production by 2025 totals approximately 124 MM b/y, another potential increase of more than tenfold from 2019-2025.[237]

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.[238] 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.

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

[235] Data from Share of Liquid Biofuels Produced In State by Volume; Figure 10 in Low Carbon Fuel Standard Data Dashboard, California Air Resources Board, https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm.

[236] *Id.*

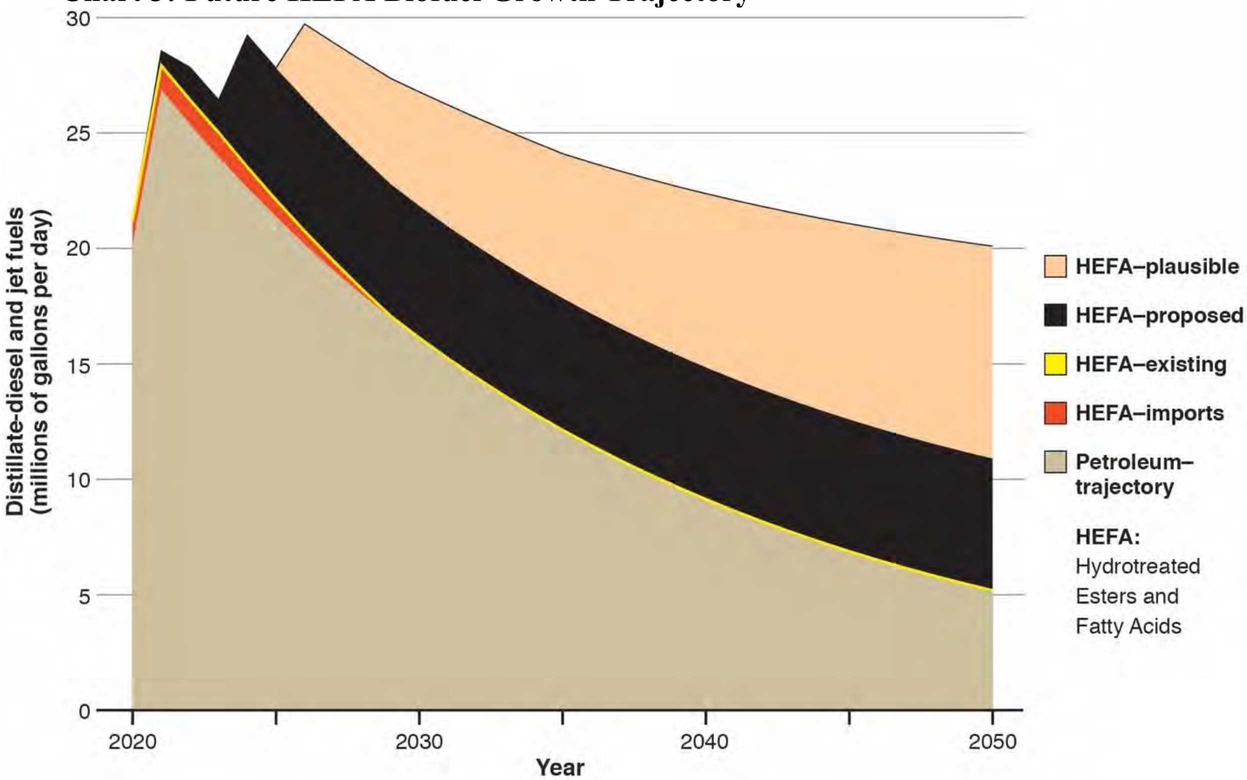
[237] *See* CEC 2021 Schremp Presentation.

[238] 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.

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.

Chart 3 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 3.

Chart 3: Future HEFA Biofuel Growth Trajectory



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[ii] 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. [239]

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[239] 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.

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.[240] 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.[241] 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 3 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.[242] HEFA growth by 2025 in the Chart 3 scenario is less than half of those plans. Had the DEIR considered that 5.2 billion gallon/year estimate by California Energy Commission staff,[243] 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 3, 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.

The cumulative emission shifting associated with biofuel production (Section VI) is also highly significant. A *conservative* estimate of cumulative emissions from currently proposed refinery biofuel projects in the County, *if* state goals to replace all diesel fuels were to be achieved more quickly than anticipated, is in the range of approximately 74 Mt to 107 Mt over ten years. *See* Table 8.

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.

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[240] *Id.*

[241] 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

[242] 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

[243] *Id.*

For example, increases in feedstock demand will implicate economic and transportation impacts to marine resources all over the world.

While the DEIR mentions in passing the Phillips 66 biofuel conversion proposal, it does not evaluate other biofuel proposals or their cumulative impacts.

> With marine vessel traffic and renewable feedstock and fuels transportation also a component of the Phillips 66 Rodeo Renewed Project, there is greater opportunity for introduction of non-native invasive species, vessel strikes and spills, even with mitigation measures implemented by the Project as described in Section 3.4. Therefore, the Project would contribute to a cumulatively significant impact on biological resources.

DEIR 4-10. These other projects, both in California and around the country, must be evaluated. For instance, vessel traffic increases will be cumulatively significant.

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 Phillips 66 2017 project proposal should be incorporated into the record for the current CEQA review; as should the record associated with the proposed terminal expansion associated with the Phillips 66 Rodeo Renewed project.

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.

The DEIR provides general references to existing contamination in its discussion of existing conditions (DEIR 3.9-8 – 9), construction impacts on hazardous waste remediation activities (DEIR 3.9-13), and decommissioning portions of the site (DEIR 2-39). However, the DEIR provides insufficient detail concerning the extent of existing contamination to the soil and groundwater, or concerning past cleanup operations currently being monitored. The analysis does reference Order No. 00-021 (DEIR at 3.9-13), but not the various past hazardous waste management activities that are completed but still subject to monitoring requirements. Ongoing hazardous waste remediation activities are being conducted under the jurisdiction of the Department of Toxic Substances Control (DTSC), which involve a land use restriction.[244] The U.S. Environmental Protection Agency (EPA) and the San Francisco Regional Water Board (Water Board) have also issued multiple past orders. EPA Resource Conservation and Recovery Act (RCRA) Order No. 09-89-0013 was issued March 13, 1989; and Waste Discharge Requirements Order R2-2004-0056 was issued in July 2004.[245] The San Francisco Bay Regional Board (Regional Board), overseeing the cleanup, issued cleanup orders for Waste Management Units (WMUs) 10, 11, 14, 31, and 32 in 2017.[246] The Regional Board approved post-closure management plans for Waste Management Units (WMUs) 1, 2, 3, 4, 5, 6, 8, 9, and 13in 2015.[247]

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[244] DTSC activities include the individual Waste Management Unit (WMU), WMU-17, US EPA number CAD000072751. The latest Post Closure Facility Permit is effective 12/19/21 and will expire 12/18/31. Number 7 of Section V Special Conditions of the Post Closure Permit specifies that a Land Use Covenant was filed 9/10/20 based on the DTSC has concluded that it is reasonably necessary to restrict the land use of the Unit in order to protect present or future human health or safety or the environment. *See* Land Use Covenant And Agreement Environmental Restrictions County of Contra Costa Assessor's Parcel Number: 159-270-006, Tesoro Refining & Marketing Company LLC DTSC Site Code: 510505: September 10, 2020; Hazardous Waste Management Program Permitting Division, Post-Closure Hazardous Waste Facility Permit for Tesoro Refining and Marketing Company LLC. Permit No. 2021/22-HWM-05, EPA ID No CAD 000 072 751, effective date December 19, 2021.

[245] Letter dated July 30, 2004 to Tesoro Refining and Marketing Company from David Elias, Regional Board.

[246] Letter dated September 1, 2016 to Frances Malamud-Roam from Michael McGuire re Revised Alternatives Analysis, Tesoro Martinez Refinery Waste Management Unit Closure Project.

[247] Letter dated July 29, 2015 to Regional Board from Michael McGuire re Post-Closure Maintenance Plan (PCMP) for Waste Management Units 1, 2, 3, 4, 5, 6, 8, 9..

Yet only WMU 4 receives mention in the DEIR (in the discussion of cultural impacts, DEIR 3.5.5).

The DEIR should have disclosed in detail all of these historic and ongoing cleanup and monitoring operations, and described the basis for its cursory conclusion that construction and operation activities will not impact them (DEIR at 3.9-13). Additionally, the DEIR should have discussed how the Project will impact transportation routes around ongoing remediation. For example, the transfer route of waste from WMU 31 into WMU 14 must traverse the Waterfront Road which, is the main road leading to the active refinery.

The DEIR should also have provided further detail regarding decommissioning plans with respect to the portions of the Refinery that will be fallowed by the Project, beyond the cursory description at DEIR 2-39. The idled equipment, and the ground on which it is located, is likely to be highly contaminated from years of operation of the refinery. The DEIR should have discussed what specifically will be done with the equipment, and how Marathon will address contamination of soil and groundwater at the location of the idled equipment.

Finally, the DEIR should have evaluated the impact of full site decommissioning, given the likely limited lifespan of the Project. As discussed in Section II, the foreseeable likelihood is that biofuel demand in California will wane significantly within the relatively near term as 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).

Such analysis of full decommissioning should take into account the fact that various oil companies refined oil at the Martinez site since 1913, roughly 60 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.

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

The DEIR inadequately addresses multiple aspects of potential Project impacts on marine resources. This failure is problematic given that, as discussed in Section II, the Project appears to contemplate an increase in ship traffic, even assuming that the chosen baseline is correct (which it is not, per Section III).

A. Increased Marine Traffic and Terminal Throughput Would Result in Significant Water Quality Impacts, With Attendant Safety Hazards

The water quality impacts from any increase in ship traffic or throughput volumes, as identified in Section III, must be thoroughly examined in all their phases. These include, at minimum, the loading process of feedstocks onto tankers and the shipping routes they take to San Francisco Bay, 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 Martinez. 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.[248] The majority of spills, however, are less than 200,000 gallons, and most of these spills happen while in port.[249] Two types of tanker will likely be used to transport feedstocks to the Facility, ocean-going tankers and barges. The final EIR must evaluate an actual worst-case spill scenario and mitigate appropriately.

California's 45-billion-dollar coastal economy has a lot to lose to a spill.[250] California commercial fisheries for instance, produced from 186-361 million pounds of fish from 2013-2015, at a value of 129-266 million dollars.[251] 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.[252]

A DEIR evaluating the environmental impacts of expanding operations at the Marathon marine terminals 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. 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. The final EIR must remedy this error.

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[248] The International Tanker Owners Pollution Federation (2016 spill statistics) at 8.
[249] *Id.*
[250] *California Ocean and Coastal Economies*, National Ocean Economics Program (March 2015).
[251] Based on California Department of Fish and Wildlife and National Marine Fisheries Service data.
[252] *See, e.g., Incident Specific Preparedness Review M/V Cosco Busan Oil Spill in San Francisco Bay Report on Initial Response Phase*, Baykeepr, OSPR, NOAA, et al. (Jan. 11, 2008).

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."[253] 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."[254] 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."[255] 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.

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."[256] 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.[257]

The 120 people who went to the hospital in Vallejo would probably agree that a release from the marine terminals would 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

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[253] Green *et al*., 2017

[254] *Id*.

[255] *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.

[256] 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/.

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

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.

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.[258] 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 substantially—evaluated in the DEIR. DEIR 3.10-17 ("new facilities would generate a new wastewater stream that would require additional treatment equipment to be added to the existing wastewater treatment plant"). 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, as stated, different feedstock will 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 instead of putting such analysis off until after the Project is completed.

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 feedstocks expected to arrive on the tankers utilizing the marine terminals' 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.

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[258] *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.

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 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.[259] Should Marathon 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 little aesthetic impact, and fails to analyze the impacts to marine environment-related aesthetics. DIER 3.2. San Francisco Bay is considered a world class scenic vista, with billions of dollars of tourism dependent on a setting of natural beauty. Yet minimal analysis has been done of what impact ship traffic would have on San Francisco Bay's aesthetics, including a significant source of light or glare (ships). Changes in

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[259] 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).

the types of ships serving the Facility and the times of day those ships are traversing San Francisco Bay are also relevant. The final EIR must take a hard look at these impacts, as well as impacts along expected transportation corridors and impacts from spill risks.

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. Air quality impacts from ship exhaust must be evaluated. These impacts must be evaluated by location, as is done for other types of impacts, for different types of ships, for every mile the ships travel, and for every community along their route, not just between the refinery and various anchorage points or arbitrary starting points such as the Golden Gate Bridge. The DEIR fails to do so, and also fails to evaluate health impacts from these routes and at various locations.[260] For instance, DEIR Table 3.3-5 evaluates only total mobile emissions, and fails to break out these emissions by source type. Impacts vary widely based on where the emissions are taking place, at sea or on land, etc. Under CEQA, the public must be informed in greater detail as to potential impacts from mobile sources. Ships will not arrive at the Project terminals 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.

Marathon does not have a good record of avoiding air quality violations at its refinery. For instance, Marathon Petroleum this year settled 58 violations stretching back to 2014. These violations included a "55-day flaring event in 2014, [during which] the refinery emitted enormous amounts of volatile organic compounds, hydrogen sulfide, sulfur dioxide and methane emissions, according to the Bay Area Air Quality Management District."[261] 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 refinery's operations, including marine terminal operations.

Provision of shore power for all ships at Marathon's terminals should also be considered as a mitigation measure prior to the 2027 implementation of California's *Ocean-Going Vessels at Berth Regulation*, described in the DEIR at 3.3-18 – 3.3-19. No implementation of these regulation is contemplated by the DEIR beyond the vague premise that the marine terminals will comply once they are forced to do so by the Air Board. The final EIR should include

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[260] Again, the DEIR confusingly piecemeals its analysis. Instead of including an easily producible table in the DEIR, it refers the public to various appendices (and even appendices to appendices) to attempt to calculate for themselves the air quality impacts of marine operations from the proposed Project. DEIR 3.3-28. Even these appendices are inadequate, as the DEIR acknowledges that it does not include all potential ship and barge traffic in its analysis. *Id*. (dividing out barge trip analysis from ocean-going vessels and admitting that "[b]arges <u>may</u> be used to transport feedstocks from third party terminals. The specific terminals have not yet been identified," emphasis added). According to one appendix, "[e]missions are calculated for the round-trip starting from the Pilot Boarding/Sea Buoy location (approximately 11 nautical miles west of the Golden Gate Bridge) to the relevant terminal." DEIR Appendix AQ-GH 15. Truncating trips like this is arbitrary and fails to accurately reflect the impact of the Project. The ships do not magically appear just outside the Golden Gate Bridge.

[261] *Marathon to pay $2 million for air quality violations at idled Martinez oil refinery*, Mercury News, Sept. 29, 2021, *available at* https://www.mercurynews.com/2021/09/29/marathon-to-pay-2-million-for-air-quality-violations-at-idled-martinez-oil-refinery/.

implementation details and timelines. Other mitigation that should be implemented include incentives for ship emissions and speed reductions that would result in air quality improvements.

According to the DEIR, mobile sources for the marine terminals are calculated using outdated EIRs from 2014 and 2015. DEIR 3.3-26 – 3.3-27. These EIRs are outside even the generous baseline contemplated in the DEIR. Average activity levels must be calculated based on actual operations, and cannot be tiered off of outdated EIRs.

D. Recreational Impacts Are Potentially Significant

The DEIR states that "the Project would have no impact to recreation. DEIR 3.1-8. This is error. San Francisco Bay is a massive recreational area, and maritime traffic has a direct impact on opportunities for recreation on the Bay. 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 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 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 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, through the Delta, 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 (*see, e.g.*, DEIR 3.4-8, 3.4-10 – 3.4-25), 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. Reference to EIRs from 2014 and 2015 is insufficient as conditions have changed since then, as mentioned earlier. *See, e.g.*, DEIR 3.4-34 (though these outdated EIRs are cited repeatedly with no evaluation of whether their analyses is still relevant).

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)."[262] 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 3.4-40. 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 incorporates 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-7(b) is insufficient because it does not contemplate effective measures to ensure safe vessel speeds and to mitigate for exceedances.

Acoustic impacts can also be extremely disruptive. As the DEIR points out, "[s]hips are the dominant source of low frequency noise in many highly trafficked coastal zones." DEIR 3.4-35. "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)."[263] Acoustic impacts must be evaluated as an environmental impact of the Project. However, in spite of the DEIR's admission that noise impacts would increase for fish and marine mammals under the Project, it still finds only minimal disturbance and concludes that "Behavioral disturbance and physical injury to fish and marine mammals from increasing intermittent vessel noise is not expected to be significant; thus impacts to special status species as a result of noise from increased vessel numbers would be less than significant." DEIR 3.4-35. No further analysis is given. This discrepancy must be explained in the final EIR, and mitigation measures, such as reducing vessel speed and the other potential mitigations 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.[264]

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 3.4-40 (also relying on the analysis in old DEIRs). 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.

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[262] Green *et al*. 2017.
[263] *Id*.
[264] 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.

> Impacts from spills would depend on the material and quantity spilled. The above-referenced EIRs address spills from light oils such as fuel oil, medium oils such as crude oil and heavy oils such as heavy crude and some fuel oils. Biofuels such as ethanol or biodiesel, which are derived from vegetable oils or animal fats, behave differently from conventional petroleum-based fuels in the environment. A discussion of hazards associated with the change of feedstocks is provided in Section 3.9 Hazards and Hazardous Materials.

DEIR 3.4-41. This discussion does not address feedstock differences, and is inadequate to address risks to wildlife. Marathon could do more, for instance to study cleanup methodologies and impacts from spills. 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. "Nonindigenous aquatic species can be introduced into the San Francisco Bay Estuary through ballast water exchange or vessel biofouling." DEIR 3.4-42. Yet the DEIR's mitigation measures are insufficient. Again, sending a flyer does not prevent the problems identified in the DEIR. DEIR 4.4-143. 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.[265]

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. Furthermore, the DEIR's analysis of noise impacts completely neglects to address noise from ship traffic. DEIR § 3.12. 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.

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[265] 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.

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.

Martinez has a high concentration of hazardous waste facilities, has a high concentration of contamination from Toxic Release Inventory chemicals. This area also suffers from high levels of health impacts.

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.[266] 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.

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

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

1. Public Trust Resources

The marine terminals that the Project targets for increased ship traffic occupies leased land, filled and unfilled. This land is California-owned sovereign land, 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.

Thank you for your consideration of these Comments.

Very truly yours,

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APPENDIX A

Karras, G., *Changing Hydrocarbons Midstream* (Karras, 2021a)

Changing Hydrocarbons Midstream

Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing

Prepared for the Natural Resources Defense Council (NRDC), by

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August 2021

ABSTRACT

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

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

ACRONYMS AND TERMS

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

CONTENTS

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.

Changing Hydrocarbons Midstream

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

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

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

Takeaways

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

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

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

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

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

INTRODUCTION

i.1 Biofuels in energy systems

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

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

i.1.1 Some different types of biofuel technologies

Corn ethanol

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

Fischer-Tropsch synthesis

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

Biofuel in the Climate System 101

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

But can the biofuel industry keep that promise?

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

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

How much of which types of biofuels we choose matters.

"Biodiesel"

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

Hydrotreating esters and fatty acids (HEFA)

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

i.2 What is HEFA technology?

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

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

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

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

Purpose-grown crops

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

Animal fats

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

Used cooking oils

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

i.2.3 HEFA processing chemistry

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

The role of hydrogen in HEFA production

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

i.2.4 What HEFA produces

"Drop in" diesel

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

"Sustainable Aviation Fuel"

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

i.3 Conversions of Crude oil refineries to HEFA

i.3.1 Current and proposed conversions of oil refineries

Phillips 66 Co. (P66) proposes to convert its petroleum refinery in Rodeo, CA into a 80,000 barrel per day (b/d) biorefinery.[2] In nearby Martinez, Marathon Petroleum Corporation (MPC) proposes a 48,000 b/d biorefinery[3] at the site where it closed a crude refinery in April 2020.[4] Other crude-to-biofuel refinery conversions are proposed or being built in Paramount, CA (21,500 b/d new capacity),[5] Bakersfield, CA (15,000 b/d),[6] Port Arthur, TX (30,700 b/d),[7] Norco, LA (17,900 b/d new capacity),[8] and elsewhere. All of these projects are super-sized compared with the 2,000–6,000 b/d projects studied as of just a few years ago.[9] The P66 Rodeo and MPC Martinez projects are the largest of their kind to be proposed or built to date. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10]

i.3.2 Repurposing of existing equipment

Remarkably, all of the crude-to-biofuel conversion projects listed above seek to use HEFA technology—none of the refiners chose Fischer-Tropsch synthesis despite its greater flexibility than HEFA technology and ability to avoid purpose-grown biomass feedstock. However, this is consistent with repurposing the plants already built. The California refiners propose to repurpose existing hydro-conversion reactors—hydrocrackers or hydrotreaters—for HEFA processing, and existing hydrogen plants to supply HEFA process hydrogen needs.[2–6] Moreover, it is consistent with protecting otherwise stranded assets; repurposed P66 and MPC assets have recently been shut down, are being shut down, or will potentially be unusable soon, as described in Chapter 1.

While understandable, this reaction to present and impending petroleum asset stranding appears to be driving our energy system toward HEFA technology instead of potentially cleaner alternatives at an enormous scale, totaling 164,500 b/d by 2024 as proposed now in California. This assets protection reaction also presents a clear potential for further HEFA expansion. Refiners could continue to repurpose petroleum refining assets which will be idled as by the replacement of gasoline with more efficient electric passenger vehicles.

Before allowing this new source of carbon to become locked into a future combustion-based transportation system, assessment of potential impacts across the HEFA fuel chain is warranted.

i.4 Key questions and concerns about crude-to-biofuel conversions

i.4.1 Potential impacts of biomass feedstock acquisition

Proposed and potential HEFA expansions in California would rapidly and substantially increase total demand for globally traded agricultural lipids production. This could worsen food insecurity, risk deforestation, biodiversity and natural carbon sink impacts from expansions of farm and pasture lands, and drive populations elsewhere to prioritize use of their remaining lipids shares for food. Biofuel, biodiversity, and climate analysts often refer to the food security impact and agriculture expansion risks in terms of food price and "indirect land use" impacts. The latter effect, on *where* a globally limited biofuel resource could be used, is often referred to by climate policy analysts as an emission-shifting or "leakage" impact. Chapter 2 reviews these potential feedstock acquisition impacts and risks.

i.4.2 Potential impacts of HEFA refinery processing

Processing a different oil feedstock is known to affect refinery hazards and emissions, and converted HEFA refineries would process a very different type of oil feedstock. The carbon intensity—emissions per barrel processed—of refining could increase because processing high-oxygen plant oils and animal fats would consume more hydrogen, and the steam reformers that refiners plan to repurpose emit some ten tons of CO_2 per ton of hydrogen produced. Explosion and fire risks could increase because byproducts of refining the new feeds pose new equipment damage hazards, and the extra hydrogen reacted with HEFA feeds would increase the frequency and magnitude of dangerous runaway reactions in high-pressure HEFA reactors. Episodic air pollution incidents could recur more frequently because refiners would partially mitigate the impacts of those hazards by rapid depressurization of HEFA reactor contents to refinery flares, resulting in acute air pollutant exposures locally. Chapter 3 assesses these potential impacts.

i.4.3 Potential impacts on climate protection pathways

A climate pathway is a road map for an array of decarbonization technologies and measures to be deployed over time. California has developed a range of potential pathways to achieve its climate goals—all of which rely on replacing most uses of petroleum with zero-emission battery-electric vehicles and fuel cell-electric vehicles (FCEVs) energized by renewable electricity. Proposed and potential HEFA biofuels growth could exceed this range of state pathways or interfere with them in several ways that raise serious questions for our future climate.

HEFA biofuels could further expand as refiners repurpose assets idled by the replacement of gasoline with electric vehicles. This could exceed HEFA caps *and* total liquid fuels volumes in the state climate pathways. Hydrogen committed to HEFA growth would not be available for FCEVs and grid-balancing energy storage, potentially slowing zero-emission fuels growth. High-carbon hydrogen repurposed for HEFA refining, which could not pivot to zero-emission FCEV fueling or energy storage, could lock in HEFA biofuels instead of supporting transitions to cleaner fuels. These critical-path climate factors are assessed in Chapter 4.

i.4.4 Alternatives, opportunities and choices

Zero emission hydrogen alternative

Renewable-powered electrolysis of water produces zero-emission hydrogen that could replace existing high-carbon hydrogen production during refinery maintenance shutdowns and HEFA conversions. Indeed, a "Hydrogen Roadmap" in state climate pathways envisions converting all refineries to renewable hydrogen. This measure could cut emissions, support the growth of FCEVs and grid-balancing energy needed to further expand renewable electricity and zero-emission fuels, and reduce local transition impacts when refineries decommission.

Window of opportunity

A crucial window of opportunity to break out of carbon lock-in has opened with the beginning of California petroleum asset stranding in 2020 and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels. The opening of this time-sensitive window underscores the urgency of early deployment for FCEV, energy storage, and zero-emission fuels which renewable-powered electrolysis could support.

Potential synergies with HEFA biofuels cap

Coupling this measure with a HEFA biofuels cap has the potential to enhance its benefits for FCEV and cleaner fuels deployment by limiting the potential for electrolysis hydrogen to instead be committed to HEFA refining during the crucial early deployment period, and has the potential to reduce HEFA refining hazard, episodic air pollution and environmental justice impacts.

i.4.5 A refinery project disclosure question

Readers should note that P66[2] and MPC[11] excluded flares and hydrogen production which would be included in their proposed HEFA projects from emission reviews they assert in support of their air permit applications. To date neither refiner has disclosed whether or not its publicly asserted project emission estimate excludes any flare or hydrogen production plant emissions. However, as shown in Chapter 3, excluding flare emissions, hydrogen production emissions, or both could underestimate project emission impacts significantly.

i.5 The scope and focus of this report

This report addresses the questions and concerns introduced above. Its scope is limited to potential fuel chain and energy system impacts of HEFA technology crude-to-biofuel conversion projects. It focuses on the California setting and, within this setting, the Phillips 66 Co. (P66) Rodeo and Marathon Petroleum Corp. (MPC) Martinez projects. Details of the data and methods supporting original estimates herein are given in a Supporting Material Appendix.[1]

1. OVERVIEW OF HEFA BIOFUEL TECHNOLOGY

All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).[2 3 4 6] "Hydrotreating" signifies a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: triacylglycerols (TAGs) and the fatty acids derived from TAGs. HEFA feedstock is biomass from the TAGs and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.

This chapter addresses how HEFA biofuel technology functions, which is helpful to assessing its potential impacts in the succeeding chapters, and explores why former and current crude oil refiners choose this technology instead of another available fuels production option.

1.1 HEFA process chemistry

Hydrocarbons formed in this process reflect the length of carbon chains in its feed. Carbon chain lengths of the fatty acids in the TAGs vary by feed source, but in oil crop and livestock fat feeds are predominantly in the range of 14–18 carbons (C14–C18) with the vast majority in the C16–C18 range.[1] Diesel is predominantly a C15–C18 fuel; Jet fuel C8–C16. The fuels HEFA can produce in relevant quantity are thus diesel and jet fuels, with more diesel produced unless more intensive hydrocracking is chosen intentionally to target jet fuel production.

HEFA process reaction chemistry is complex, and in practice involves hard-to-control process conditions and unwanted side-reactions, but its intended reactions proceed roughly in sequence to convert TAGs into distillate and jet fuel hydrocarbons.[12 13 14 15 16 17 18 19 20 21 22] Molecular sites of these reactions in the first step of HEFA processing, hydrodeoxygenation (HDO), are illustrated in Diagram 1 below.

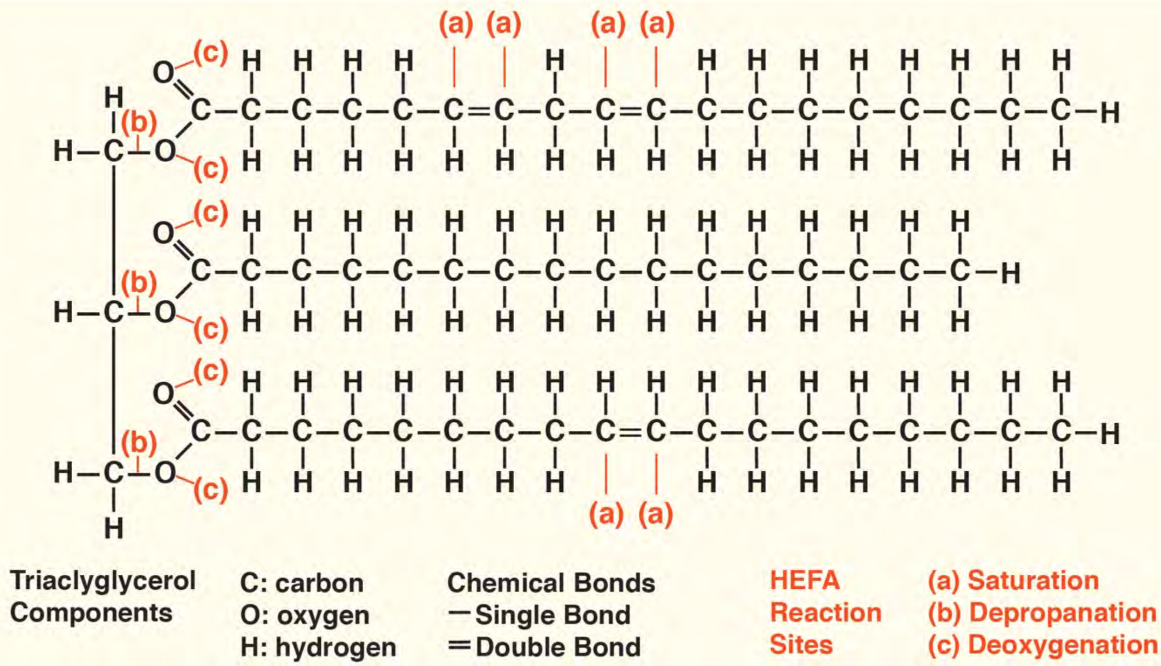


Diagram 1. Hydrodeoxygenation (HDO) of a triacylglycerol (TAG).

Fatty acids are "saturated" by bonding hydrogen to their carbon atoms. *See* (a) in Diagram. This tends to start first. Then, the fatty acids are broken free from the three-carbon "propane knuckle" of the TAG (Diagram 1, left) by breaking its bonds to them via hydrogen insertion. (Depropanation; *see* (b) in Diagram 1.) Still more hydrogen bonds with the oxygen atoms (c), to form water (H_2O), which is removed from the hydrocarbon process stream. These reactions yield water, propane, some unwanted but unavoidable byproducts (not shown in the diagram for simplicity), and the desired HDO reaction products—hydrocarbons which can be made into diesel and jet fuel.

But those hydrocarbons are not yet diesel or jet fuel. Their long, straight chains of saturated carbon make them too waxy. Fueling trucks or jets with wax is risky, and prohibited by fuel specifications. To de-wax them, those straight-chain hydrocarbons are turned into their branched-chain isomers.

Imagine that the second-to-last carbon on the right of the top carbon chain in Diagram 1 takes both hydrogens bonded to it, and moves to in between the carbon immediately to its left and one of the hydrogens that carbon already is bonded to. Now imagine the carbon at the end of the chain moves over to where the second-to-last carbon used to be, and thus stays attached to the carbon chain. That makes the straight chain into its branched isomer. It is isomerization.

Isomerization of long-chain hydrocarbons in the jet–diesel range is the last major HEFA process reaction step. Again, the reaction chemistry is complex, involves hard-to-control process conditions and unwanted side reactions at elevated temperatures and pressures, and uses a lot of hydrogen. But these isomerization reactions, process conditions, and catalysts are markedly different from those of HDO.[9 14–17 19 20] And these reactions, process conditions, catalysts and hydrogen requirements also depend upon whether isomerization is coupled with intentional hydrocracking to target jet instead of diesel fuel production.[1] Thus this last major set of HEFA process reactions has, so far, required a separate second step in HEFA refinery configurations. For example, MPC proposes to isomerize the hydrocarbons from its HDO reactors in a separate second-stage hydrocracking unit to be repurposed from its shuttered Martinez crude refinery.[3]

HEFA isomerization requires very substantial hydrogen inputs, and can recycle most of that hydrogen when targeting diesel production, but consumes much more hydrogen for intentional hydrocracking to boost jet fuel production, adding significantly to the already-huge hydrogen requirements for its HDO reaction step.[1]

The role and impact of heat and pressure in the HEFA process

Hydro-conversion reactions proceed at high temperatures and extremely high pressures. Reactors feeding gas oils and distillates of similar densities to HEFA reactor feeds run at 575–700 ºF and 600–2,000 pounds per square inch (psi) for hydrotreating and at 575–780 ºF and 600–2,800 psi for hydrocracking.[16] That is during normal operation. The reactions are exothermic: they generate heat in the reactor on top of the heat its furnaces send into it. Extraordinary steps to handle the severe process conditions become routine in hydro-conversion. Hydrogen injection and recycle capacities are oversized to quench and attempt to control reactor heat-and-pressure rise.[16 22] When that fails, which happens frequently as shown in a following chapter, the reactors depressurize, dumping their contents to emergency flares. That is during petroleum refining.

Hydro-conversion reaction temperatures increase in proportion to hydrogen consumption,[21] and HDO reactions can consume more hydrogen, so parts of HEFA hydro-conversion trains can run hotter than those of petroleum refineries, form more extreme "hot spots," or both. Indeed, HEFA reactors must be designed to depressurize rapidly.[22] Yet as of this writing, no details of design potential HEFA project temperature and pressure ranges have been reported publicly.

1.2 Available option of repurposing hydrogen equipment drives choice of HEFA

Refiners could choose better new biofuel technology

Other proven technologies promise more flexibility at lower feedstock costs. For example, Fischer-Tropsch synthesis condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce biogas, gasoline, jet fuel, or diesel biofuels.[23] Cellulosic biomass residues can be gasified for Fischer-Tropsch synthesis.[24] This alternative promises lower cost feedstock than HEFA technology and the flexibility of a wider range of future biofuel sales, along with the same ability to tap "renewable" fuel subsidies as HEFA technology. Refiners choose HEFA technology for a different reason.

Refiners can repurpose existing crude refining equipment for HEFA processing

Hydro-conversion reactors and hydrogen plants which were originally designed, built, and used for petroleum hydrocracking and hydrotreating could be repurposed and used for the new and different HEFA feedstocks and process reactions. This is in fact what the crude-to-biofuel refinery conversion projects propose to do in California.[2 3 5 6]

In the largest HEFA project to be proposed or built, P66 proposes to repurpose its 69,000 barrel/day hydrocracking capacity at units 240 and 246 combined, its 16,740 b/d Unit 248 hydrotreater, and its 35,000 b/d Unit 250 hydrotreater for 100% HEFA processing at Rodeo.[2 25] In the second largest project, MPC proposes to repurpose its 40,000 b/d No.2 HDS hydrotreater, 70,000 b/d No. 3 HDS hydrotreater, 37,000 b/d 1st Stage hydrocracker, and its 37,000 b/d 2nd Stage hydrocracker for 100% HEFA processing at Martinez.[3 26]

For hydrogen production to feed the hydro-conversion processing P66 proposes to repurpose 28.5 million standard cubic feet (SCF) per day of existing hydrogen capacity from its Unit 110 and 120 million SCF/d of hydrogen capacity from the Air Liquide Unit 210 at the same P66 Rodeo refinery.[2 25 27] MPC proposes to repurpose its 89 million SCF/d No. 1 Hydrogen Plant along with the 35 million SCF/d Air Products Hydrogen Plant No. 2 at the now-shuttered MPC Martinez refinery.[3 4 11 26]

By converting crude refineries to HEFA biofuel refiners protect otherwise stranded assets

Motivations to protect otherwise stranded refining assets are especially urgent in the two largest crude-to-biofuel refining conversions proposed to date. Uniquely designed and permitted to rely on a landlocked and fast-dwindling crude source already below its capacity, the P66 San Francisco Refinery has begun to shutter its front end in San Luis Obispo County, which makes its unheated pipeline unable to dilute and send viscous San Joaquin Valley crude to Rodeo.[28] This threatens the viability of its Rodeo refining assets—as the company itself has warned.[29] The MPC Martinez refinery was shut down permanently in a refining assets consolidation, possibly accelerated by COVID-19, though the pandemic closed no other California refinery.[30]

The logistics of investment in new and repurposed HEFA refineries as a refining asset protection mechanism leads refiners to repurpose a refining technology that demands hydrogen, then repurpose refinery hydrogen plants that supply hydrogen, then involve other companies in a related sector—such as Air Liquide and Air products—that own otherwise stranded hydrogen assets the refiners propose to repurpose as well.

Refiners also seek substantial public investments in their switch to HEFA biofuels. Tepperman (2020)[31] reports that these subsidies include federal "Blenders Tax" credits, federal "Renewable Identification Number" credits, and state "Low Carbon Fuel Standard" credits that one investment advisor estimated can total $3.32 per gallon of HEFA diesel sold in California. Krauss (2020)[32] put that total even higher at $4.00 per gallon. Still more public money could be directed to HEFA jet fuel, depending on the fate of currently proposed federal legislation.[33]

2. UPSTREAM — IMPACT OF FEEDSTOCK CHOICES

The types, amounts, and characteristics of energy feedstocks have repercussions across the energy system and environment. Choosing HEFA technology would lock into place a particular subset of the biomass carbon on our planet for use in energy production. It would further create a need for continued and potentially additional hydrogen use. This chapter evaluates the environmental impacts of feedstock acquisition and feedstock choices in HEFA production.

2.1 Proposed feedstock use by the Phillips 66, Marathon, and other California projects

2.1.1 Biomass volume

The proposed conversions at P66 and MPC, and attendant use of HEFA feedstocks, are very large in scale. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10] The feedstock capacity of its HEFA biorefinery proposed in Rodeo, CA reported by P66 is 80,000 barrels per day (b/d).[2] With a feedstock capacity of 48,000 b/d, the MPC Martinez, CA project could then be the second largest HEFA refinery to be proposed or built worldwide.[3] The World Energy subsidiary, AltAir, expansion in Paramount, CA, which also plans to fully convert a petroleum refinery, would add 21,500 b/d of new HEFA feedstock capacity.[5] And Global Clean Energy Holdings, Inc. plans to convert its petroleum refinery in Bakersfield, CA into a HEFA refinery[6] with at least 15,000 b/d of new capacity. Altogether that totals 164,500 b/d of new HEFA feedstock capacity statewide.

The aggregate proposed new California feedstock demand is some 61–132 *times* the annual feedstock demand for HEFA refining in California from 2016–2019.[34] But at the same time, the proposed new California biofuel feed demand is only ten percent of California refinery demand for crude oil in 2019,[35] the year before COVID-19 forced temporary refining rate cuts.[36] This raises a potential for the new HEFA feed demand from crude-to-biofuel refinery conversions proposed here today to be only the beginning of an exponentially increasing trend.

2.1.2 Biomass type

HEFA technology, proposed at all of the California refineries currently proposing conversion to biofuel production, uses as feedstock triacylglycerols (TAGs) and fatty acids derived from TAGs (Chapter 1). Primary sources of these biomass lipids in concentrations and amounts necessary for HEFA processing are limited to oil crop plants, livestock fats, and fish oils. Existing U.S. biofuels production has tapped soybean oil, distillers corn oil, canola oil, cottonseed oil, beef tallow, pork lard and grease, poultry fats, fish oils from an unreported and likely wide range of species, and used cooking oil—lipids that could be recovered from uses of these primary sources, also known as "yellow grease."[37] [38] [39]

2.1.3 Other uses for this type of biomass

Importantly, people already use these oils and fats for many other needs, and they are traded globally. Beside our primary use of this type of biomass to feed ourselves directly, we use it to feed livestock in our food system, to feed our pets, and to make soap, wax, lubricants, plastics, cosmetic products, and pharmaceutical products.[40]

2.2 Indirect impacts of feedstock choices

2.2.1 Land use and food system impacts

Growing HEFA biofuel feedstock demand is likely to increase food system prices. Market data show that investors in soybean and tallow futures have bet on this assumption.[41] [42] [43] This pattern of radically increasing feedstock consumption and the inevitable attendant commodity price increases threatens significant environmental and human consequences, some of which are already emerging even with more modestly increased feedstock consumption at present.

As early as 2008, Searchinger et al.[44] showed that instead of cutting carbon emissions, increased use of biofuel feedstocks and the attendant crop price increases could expand crop land into grasslands and forests, reverse those natural carbon sinks, and cause food-sourced biofuels to emit more carbon than the petroleum fuels they replace. The mechanism for this would be global land use change linked to prices of commodities tapped for both food and fuel.[44]

Refiners say they will not use palm oil, however, that alone does not solve the problem. Sanders et al. (2012)[45] showed that multi-nation demand and price dynamics had linked soy oil, palm oil, food, and biofuel feedstock together as factors in the deforestation of Southeast Asia for palm oil. Santeramo (2017)[46] showed that such demand-driven changes in prices act across the oil crop and animal fat feedstocks for HEFA biofuels in Europe and the U.S. Searle (2017)[47] showed rapeseed (canola) and soy biofuels demand was driving palm oil expansion; palm oil imports increase for other uses of those oils displaced by biofuels demand.

Additionally, The Union of Concerned Scientists (2015),[48] Lenfert et al. (2017),[49] and Nepstad and Shimada (2018)[50] linked soybean oil prices to deforestation for soybean plantations in the Brazilian Amazon and Pantanal. By 2017, some soy and palm oil biofuels were found to emit more carbon than the petroleum fuels they are meant to replace.[47 51] By 2019 the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES) warned large industrial biofuel feedstock plantations threaten global biodiversity.[52] By 2021 the Intergovernmental Panel on Climate Change joined the IPBES in this warning.[53] At high yields and prices, up to 79 million acres could shift to energy crops by 2030 in the U.S. alone.[40] And once a biofuel feedstock also used for food is locked in place, the human impacts of limiting land conversion could potentially involve stark social injustices, notably food insecurity and hunger.[44]

Work by many others who are not cited here contributed to better understanding the problem of our growing fuel chain-food chain interaction. Potential biodiversity loss, such as pollinator population declines, further risks our ability to grow food efficiently. Climate heating threatens more frequent crop losses. The exact tipping point, when pushing these limits too hard might turn the natural carbon sinks that biofuels depend upon for climate benefit into global carbon sources, remains unknown.

2.1.2 Impact on climate solutions

Technological, economic, and environmental constraints across the arrays of proven technologies and measures to be deployed for climate stabilization limit biofuels to a targeted role in sectors for which zero-emission fuels are not yet available.[53 54 55 56 57 58 59 60 61] And these technologies and measures require place-based deployment actions understood in a larger global context—actions that must be planned, implemented, and enforced by the political jurisdictions in each geography, but whose effect must be measured on a worldwide scale. California policy makers acted on this fact by expressly defining an in-state emission reduction which results in an emission increase elsewhere as inconsistent with climate protection.[62]

Tapping a biomass resource for biofuel feedstock can only be part of our state or national climate solution if it does not lead to countervailing climate costs elsewhere that wipe out or overtake any purported benefits. Thus, if California takes biomass from another state or nation which that other state or nation needs to cut emissions there, it will violate its own climate policy, and more crucially, burning that biofuel will not cut carbon emissions. Moreover, our climate policy should not come at the cost of severe human and environmental harms that defeat the protective purpose of climate policy.

Use of biofuels as part of climate policy is thus limited by countervailing climate and other impacts. Experts that the state has commissioned for analysis of the technology and economics of paths to climate stabilization suggest that state biofuel use should be limited to the per capita share of sustainable U.S. production of biofuel feedstock.[54 55] Per capita share is a valid benchmark, and is used herein, but it is not necessarily a basis for just, equitable, or effective policy. Per capita, California has riches, agriculture capacity, solar energy potential, and mild winters that populations in poorer, more arid, or more polar and colder places may lack. Accordingly, the per capita benchmark applied in Table 1 below should be interpreted as a conservative (high) estimate of sustainable feedstock for California HEFA refineries.

Table 1. U.S. and California lipid supplies *v.* potential new lipid feedstock demand from crude-to-biofuel refinery conversions now planned in California.

***MM t/y:** million metric tons/year*

Lipids supply	U.S. (MM t/y)	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.

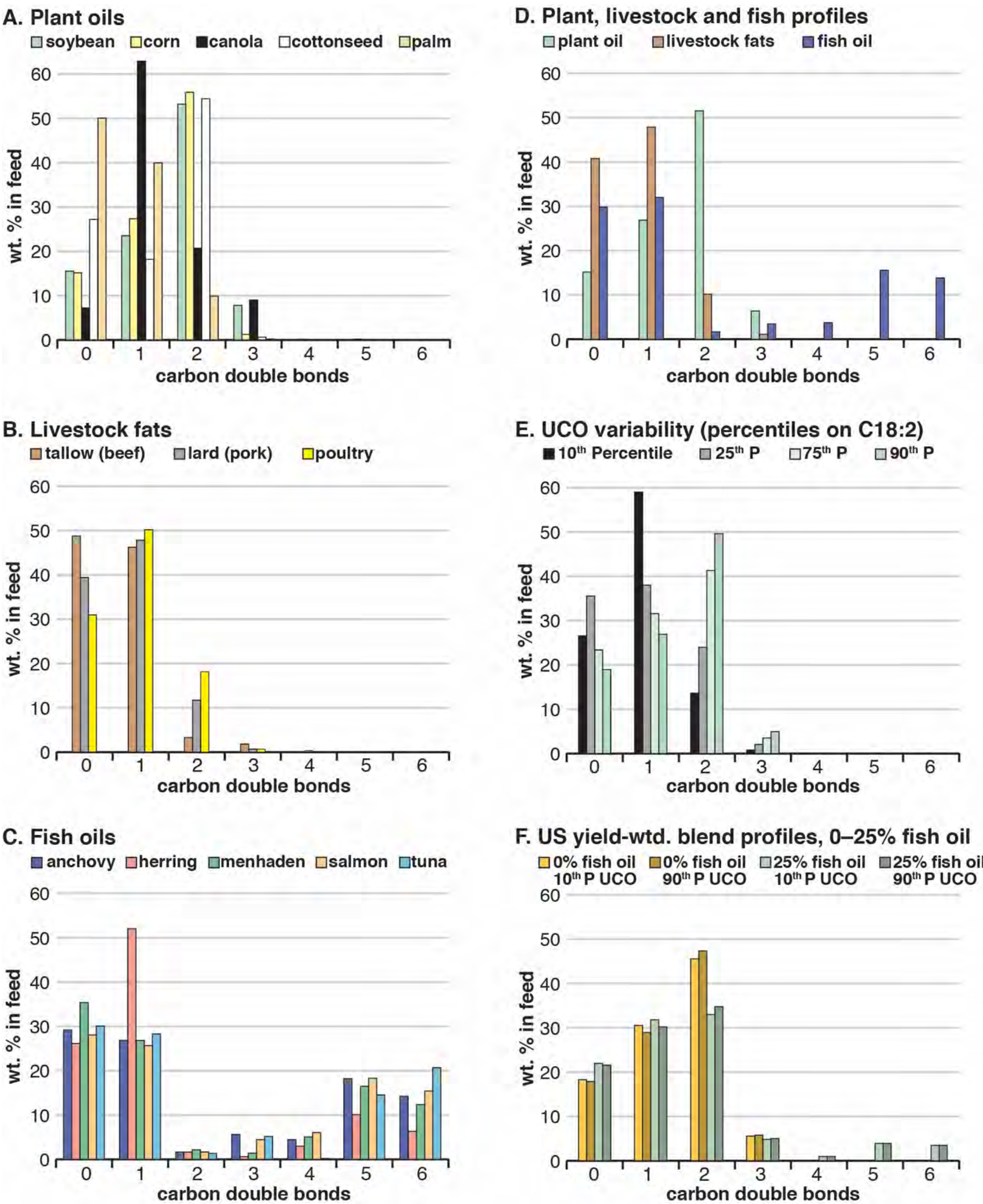
In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock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

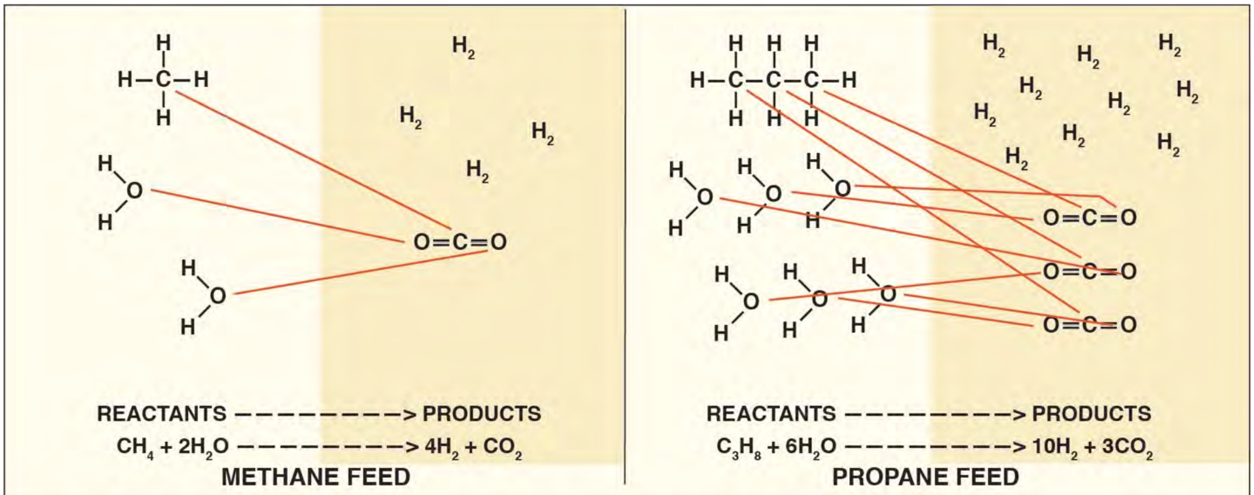


Diagram 2. Hydrogen steam reforming: reforming and shift reactions.
As the reforming and shift reactions produce hydrogen (H_2) from the hydrogen atoms (H) in hydrocarbons and steam, they bond the left-over carbon (C) and oxygen (O) atoms in those reactants together to form carbon dioxide (CO_2). This 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]

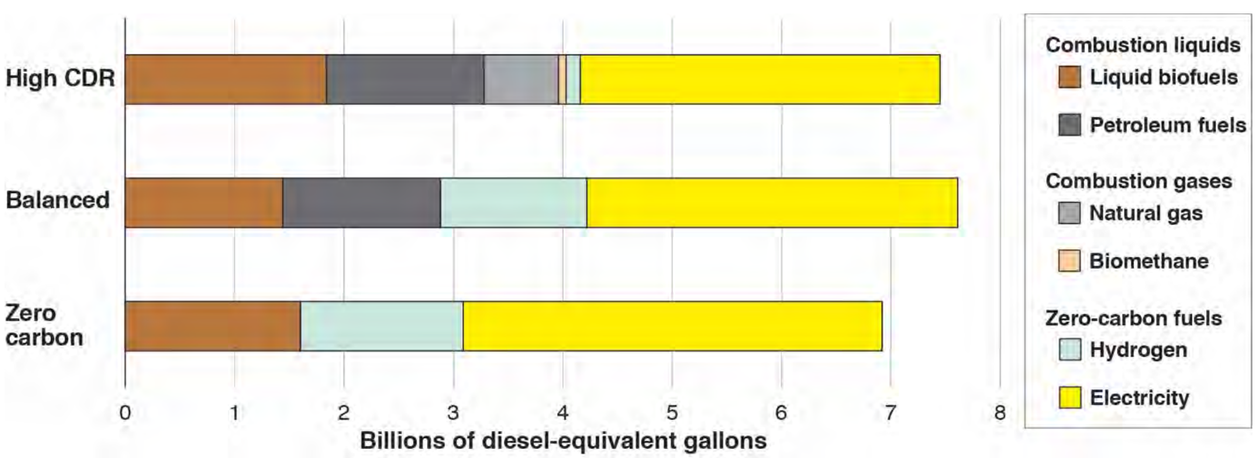
Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by 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 <u>State climate pathway liquid fuels volume benchmarks that HEFA biofuels growth could affect</u>

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]

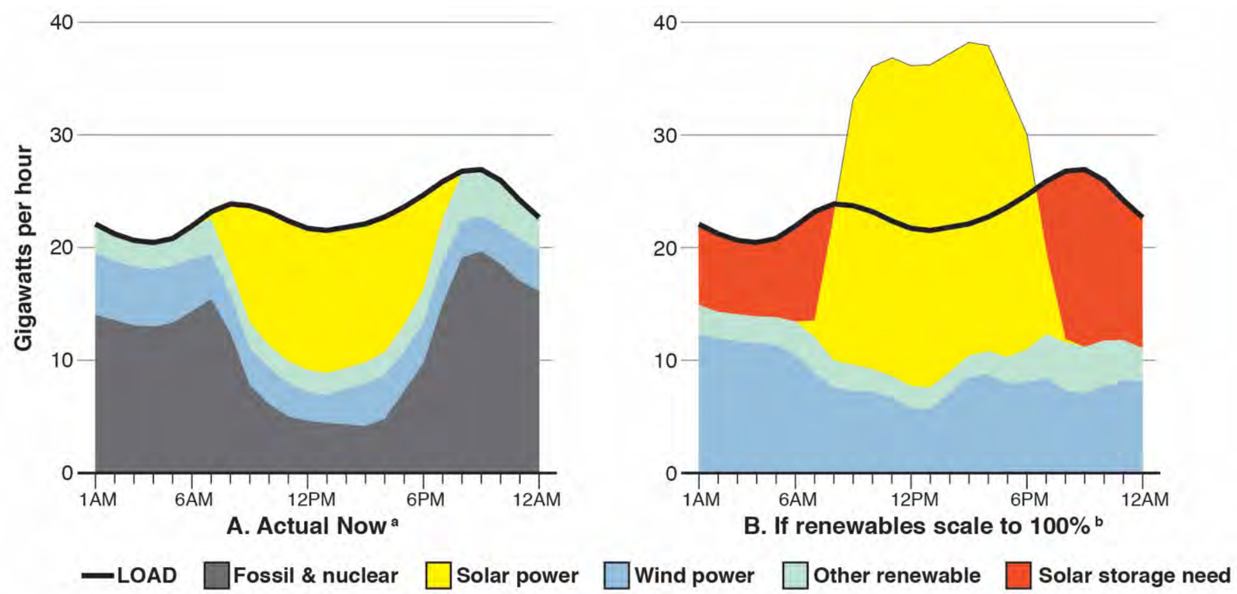
Renewable-powered electrolysis for future solar and wind power growth

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 <u>HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes</u>

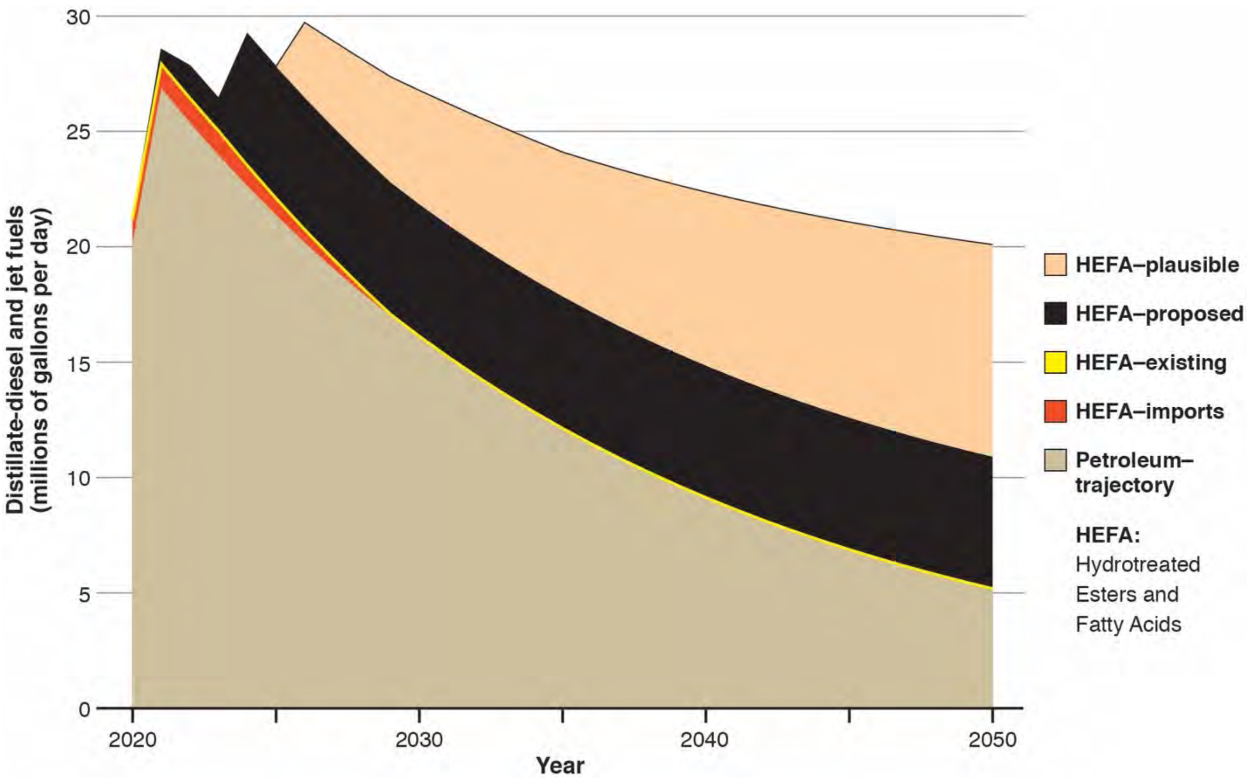
Proposed projects would exceed HEFA biofuel caps

Current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by P66, MPC, AltAir and GCE for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.[1–6] If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0–1.5 billion gal./y in state climate pathways (§4.1.2).

Continued repurposing of idled crude refining assets for HEFA biofuels could exceed the total liquid combustion fuels volume benchmarks in state climate pathways

Further HEFA biofuels growth, driven by incentives for refiners to repurpose soon-to-be-stranded crude refining assets before FCEVs can be deployed at scale, could exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up (§ 4.1.4), and refiners would be highly incentivized to protect those otherwise stranded assets (Chapter 1).

Chart 4 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 4.



4. Combustion fuels additive potential of HEFA diesel and jet production in California.

As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillate-diesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lower-carbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs.

Petroleum-trajectory for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J:G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020–2021 reflect the expected partial rebound from COVID-19.

HEFA-imports and **HEFA-existing** are the mean D+J "renewable" volumes imported, and refined in the state, respectively, from 2017–2019. The potential in-state expansion shown could squeeze out imports.

HEFA-proposed is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively.

HEFA-plausible: as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways,[55] and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market[92] anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H_2 demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J : D product slate ratio growing from 1: 5.3 to 1: 2, during 2025–2035.

For data and methodological details see Table A7.[1]

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.[1.] HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6–3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.[55] This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market—a fuel share which HEFA refiners would then be motivated to retain.

This climate impact of HEFA biofuels growth is reasonably foreseeable

The scenario shown in Chart 4 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.[92] HEFA growth by 2025 in the Chart 4 scenario is less than half of those plans. State climate pathways reported by Mahone et al.[55] replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 4, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets—and there are additional reasons why HEFA biofuel could become locked-in, as discussed below.

4.2.2 Continued use of steam reforming for refinery hydrogen could interfere with meeting state climate pathway benchmarks for electrolysis hydrogen energy integration, and lock HEFA biofuels in place instead of supporting transitions to zero-emission fuels

In contradiction to the conversion of refineries to renewable hydrogen in state climate pathways (§4.1.3), refiners propose to repurpose their high-carbon steam reforming hydrogen production assets for HEFA biofuels refining (chapters 1, 3). This would foreclose the use of that hydrogen for early deployment of ZEVs and renewable energy storage, the use of those sites for potentially least-cost FCEV fueling and renewable grid-balancing, and the future use of that hydrogen by HEFA refiners in a pivot to zero emission fuels. These potential impacts, together with HEFA refiner motivations to retain market share (§ 4.2.1), could result in HEFA diesel becoming a locked-in rather than a transitional fuel.

Repurposing refinery steam reforming for HEFA would circumvent a renewable hydrogen benchmark and interfere with early deployment for FCEVs and energy storage, slowing growth in ZEV hydrogen fuel and renewable energy for ZEV fuels production

Repurposing refinery steam reforming for HEFA fuels, as refiners propose,[2–6] instead of switching crude refining to renewable hydrogen, as the hydrogen roadmap in state climate pathways envisions,[58] could foreclose a very significant deployment potential for zero-emission fuels. Nearly all hydrogen production in California now is steam reforming hydrogen committed to oil refining.[56] Statewide, crude refinery hydrogen capacity totals ~1,216 MMSCFD,[88] some 980 times renewable hydrogen use for transportation in 2019 (1.24 SCFD)[83] and ~450 times planned 2021 electrolysis hydrogen capacity (~2.71 MMSCFD).[58] Repurposing crude refining hydrogen production for HEFA refining would perpetuate the commitment of this hydrogen to liquid combustion fuels instead of other potential uses. Importantly, that hydrogen would not be available for early deployment of FCEVs in the hard-to-electrify long haul freight and shipping sectors, or energy storage grid-balancing that will be needed for solar and wind power growth to fuel both zero emission FCEVs and BEVs.

By blocking the conversion of idled refinery hydrogen capacity to renewable hydrogen, repurposing idled crude refinery steam reforming for HEFA biofuels could slow ZEV fuels growth. Chart 5 below illustrates the scale of several potential impacts. Hydrogen demand for HEFA biofuels could exceed that for early deployment of FCEVs (Chart, 2025), exceed hydrogen demand for energy storage grid-balancing (Chart, 2045), and rival FCEV fuel demand for hydrogen in climate pathways through mid-century (*Id.*). ZEV growth could be slowed by foreclosing significant potential for zero-carbon hydrogen and electricity to produce it.

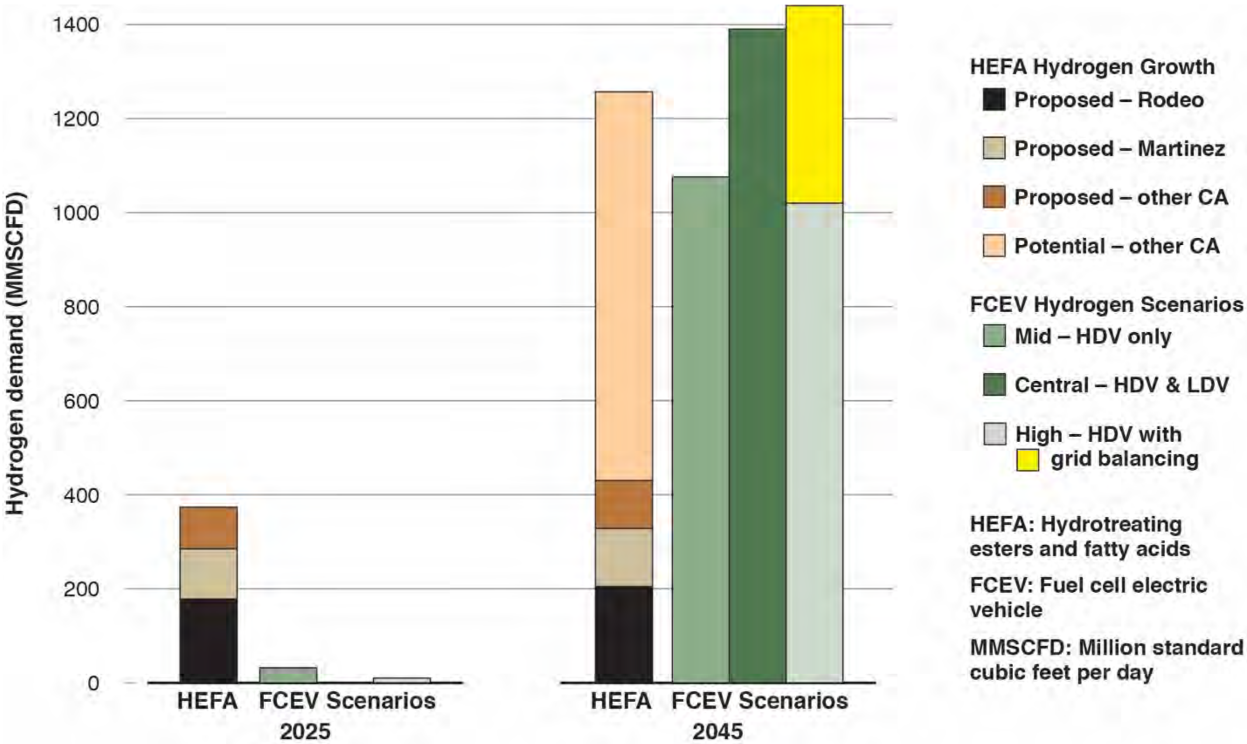
Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

Repurposing idled crude refinery steam reforming for HEFA biofuel production would foreclose reuse of otherwise idled refinery sites for renewable-powered electrolysis hydrogen. This site foreclosure impact could be important because of the potential electrolysis sites availability and location. Proximity to end-use is among the most important factors in the feasibility of renewable hydrogen build-out,[58] and refineries are near major California freight and shipping corridors and ports, where dense land uses make the otherwise idled sites especially useful for electrolysis siting. Repurposing crude refineries for HEFA biofuels could thus slow the rapid expansion of renewable-powered electrolysis hydrogen needed in climate pathways.

Continued use of steam reforming would lock HEFA refiners out of future ZEV fueling, further contributing to HEFA combustion fuels lock-in

Committing HEFA refineries to carbon-intensive steam reforming hydrogen would lock the refiners, who then would not be able to pivot toward future fueling of zero-emission FCEVs, into continued biofuel production. HEFA refiners would thus compete with hydrogen-fueled FCEVs in the new markets for fuels to replace petroleum diesel. In this HEFA growth scenario, the hydrogen lock-in, electrolysis site lockout, and ZEV fuel impacts described directly above could be expected to reinforce their entrenched position in those markets. This would have the effect of locking refiners into biofuels instead of ZEV fuels, thereby locking-in continued biofuel use at the expense of a transition to zero-emission fuels.

Crucially, multiple state pathway scenario analyses[54–56 58] show that the simultaneous scale-up of FCEVs in hard-to-electrify sectors, renewable-powered electrolysis for their zero-emission fuel, and solar and wind power electricity to produce that hydrogen, already faces substantial challenges—apart from this competition with entrenched HEFA biofuel refiners.



5. Potential growth in hydrogen demand for HEFA biorefineries, fuel cell electric vehicle (FCEV) goods movement, and renewable electricity grid balancing to 2025 and 2045.

HEFA biorefineries could slow the growth of zero-emission goods movement, and of renewable electricity, by committing limited hydrogen supplies to drop-in diesel before the cleaner technologies ramp up (chart, 2025), by rivaling their demand for large new hydrogen supplies through mid-century (chart, 2045), and by committing to the wrong type of hydrogen production technology. H_2 supplied by electrolysis of water with renewable electricity could fuel FCEVs to decarbonize long-haul goods movement, and could store peak solar and wind energy to balance the electricity grid, enabling further growth in those intermittent energy resources. However, nearly all California H_2 production is committed to oil refining as of 2021. Refiners produce this H_2 by carbon-intensive steam reforming, and propose to repurpose that fossil fuel H_2 technology, which could not pivot to zero-emission FCEVs or grid balancing, in their crude-to-biofuel refinery conversions.

HEFA proposed based on H_2 demand estimated for P66 Rodeo, MPC Martinez, and other California HEFA projects proposed or in construction as of May 2021. H_2 demand increases from 2025–2045 as HEFA feedstock, jet fuel, and H_2/b demands increase. For data and methods details *see* Table A7.[1]

HEFA potential based on H_2 production capacity at California petroleum refineries, additional to that for currently proposed projects, which could be idled and repurposed for potential HEFA projects along the trajectory shown in Chart 4. *See* Table A7 for data and details of methods.[1]

FCEV Mid – HDV only from Mahone et al. (2020b),[56] FCEVs are ~2% and 50% of new heavy duty vehicle sales in California and other U.S. western states by 2025 and 2045, respectively.[56]

Central – HDV & LDV from Austin et al. (2021), H_2 for California transportation, central scenario, LC1.[57]

High – HDV with grid balancing from Reed et al. (2020), showing here two components of total demand from their high case in California: non-LDV H_2 demand in ca. 2025 and 2045, and H_2 demand for storage and firm load that will be needed to balance the electricity grid as solar and wind power grow, ca. 2045.[58]

4.2.3 Potential carbon emissions could exceed the 2050 climate target

CO_2e emissions from the HEFA growth scenario were estimated based on LCFS carbon intensity values[86] weighted by the HEFA fuels mix in this scenario,[1] accounting for emission shifting effects described in Chapter 2. Accounting for this emission shift that would be caused by replacing petroleum with excess HEFA biofuel use in California at the expense of abilities to do so elsewhere—excluding any added land use impact—is consistent with the LCFS and state climate policy regarding emission "leakage."[62] Results show that HEFA diesel and jet fuel CO_2e emissions in this scenario could reach 66.9 million tons (Mt) per year in 2050. *See* Table 5.

Table 5. Potential CO_2e emissions in 2050 from HEFA distillates refined and used in California.

Distillates volume		
HEFA distillates refined and burned in CA [a]	5.47	billion gallons per year
CA per capita share of lipid-based biofuel [b]	0.58	billion gallons per year
Excess lipids shifted to CA for HEFA biofuel [c]	4.89	billion gallons per year
Distillate fuels mix		
HEFA diesel refined and burned in CA [d]	66.7	percentage of distillates
HEFA jet fuel refined and burned in CA [d]	33.3	percentage of distillates
Fuel chain carbon intensity		
HEFA diesel carbon intensity [e]	7.62	kg CO_2e/gallon
HEFA jet fuel carbon intensity [e]	8.06	kg CO_2e/gallon
Petroleum diesel carbon intensity [e]	13.50	kg CO_2e/gallon
Petroleum jet fuel carbon intensity [e]	11.29	kg CO_2e/gallon
Emissions (millions of metric tons as CO_2e)		
From CA use of per capita share of lipids	4.50	millions of metric tons per year
From excess CA HEFA use shifted to CA	37.98	millions of metric tons per year
Emissions shift to other states and nations [f]	24.44	millions of metric tons per year
Total HEFA distillate emissions	66.92	millions of metric tons per year

a. Potential 2050 HEFA distillates refinery production and use in California in the scenario shown in Chart 4.[1]
b. Statewide per capita share of U.S. farm yield for all uses of lipids used in part for biofuels, from data in Table 1, converted to distillates volume based on a feed specific gravity of 0.914 and a 0.809 feed-to-distillate fuel conversion efficiency. Importantly, these purpose-grown lipids have other existing uses (Chapter 2).
c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used elsewhere to replace petroleum with HEFA biofuels. Per capita share of total U.S. production for all uses, rather than that share of lipids available for biofuel, represents a conservative assumption in this estimate.
d. Distillate fuels mix in 2050 (1 gallon jet fuel to 3 gallons diesel) as described in Table A7 part f.[1]
e. Carbon intensity (CI) values from tables 3, 7-1, and 8 of the California LCFS Regulation.[86] HEFA values used (shown) were derived by apportioning "fats/oils/grease residues" and "any feedstocks derived from plant oils" at 31% and 69%, respectively, based on the data in Table 1.
f. Future emissions that would not occur if other states and nations had access to the lipid feedstock committed to California biofuel refining and combustion in excess of the state per capita share shown. Shifted emissions based on the difference between HEFA and petroleum CI values for each fuel, applied to its fuels mix percent of excess lipid-based distillates shifted to CA for HEFA biofuel. Accounting for emissions caused by replacing petroleum in CA *instead of* elsewhere, separately from any added land use impact, is consistent with the LCFS and state climate policy regarding "leakage."[62] Total emissions thus include shifted emissions.

Emissions from the remaining petroleum distillate fuels in this scenario, ~5,113,000 gal./d or 1.87 billion gal./y (Chart 4; Table A7[1]), would add 22.1–24.2 Mt/y, if diesel is 25–75% of the 2050 petroleum distillates mix, at the petroleum carbon intensities in Table 5. Thus, distillate transportation fuel emissions alone (89–91 Mt/y) could exceed the 86.2 Mt/y 2050 state target for CO_2e emissions from all activities statewide.[77] Total 2050 emissions would be larger unless zeroed out in all other activities statewide. Repurposing idled petroleum refinery assets for HEFA biofuels threatens state climate goals.

4.3 A zero-emission electrolysis hydrogen alternative can be deployed during a crucial window for breaking carbon lock-in: HEFA biofuels growth could impact the timing, and thus the emission prevention, clean fuels development, and transition benefits, of this zero-emission electrolysis hydrogen alternative.

Potential benefits to climate pathways from converting hydrogen production to renewable-powered electrolysis (electrolysis) at refinery sites were assessed with and without HEFA biofuels expansion. The "HEFA Case" captures proposed and potential HEFA growth; the "No HEFA Case" is consistent state climate pathways that exclude purpose-grown lipids-derived biofuels in favor of cellulosic residue-derived biofuels.[54 55] Conversion to electrolysis is assumed to occur at crude refineries in both cases, consistent with the hydrogen road map in state climate pathways,[58] but as an early deployment measure—assumed to occur during 2021–2026. This measure could reduce refinery carbon intensity, increase zero-emission transportation and electricity growth, and reduce local transition impacts significantly, and would be more effective if coupled with a cap on HEFA biofuels.

4.3.1 Electrolysis would prevent HEFA biofuels from increasing the carbon intensity of hydrocarbon fuels refining

Deployment timing emerges as the crucial issue in this analysis. "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating. Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts."[70] The design phase for HEFA refinery conversions, and petroleum refinery turnarounds that occur on 3- to 5-year cycles are critical insertion points for electrolysis in place of carbon-intensive steam reforming. This zero-emission measure would cut the carbon intensity of refining at any time, however, climate stabilization benefit is directly related to the cumulative emission cut achieved, so the effectiveness of this measure would also depend upon how quickly it would be deployed.

Refining CI benefits in the HEFA Case

Replacing steam reforming with electrolysis could cut the carbon intensity (CI) of HEFA refining by ~72–79%, from ~76–101 kg/b to ~21 kg/b refinery feed (Chapter 3). This would cut the CI of HEFA fuels processing from significantly above that of the average U.S. petroleum refinery (~50 kg/b crude; *Id.*) to significantly below the CI of the average U.S. crude refinery.

Refining CI benefits in the No HEFA Case

Replacing steam reforming with electrolysis at petroleum refineries would reduce CI by ~34% based on San Francisco Bay Area data,[66] however, in other states or nations where refiners run less carbon-intensive crude and product slates than in California, this ~34% may not apply.[64]

Refining CI reduction effectiveness

Cumulative emission cuts from hydrogen production would be the same in both cases since hydrogen emissions would be eliminated from HEFA refineries in both cases. Based on the CI values above and the HEFA growth trajectory[1] in Chart 4 this measure could prevent ~194–282 million tons (Mt) of CO_2 emission from HEFA hydrogen production through 2050. Petroleum refinery emissions could be cut by 103 Mt through 2050, based on the median mixed feed CI of steam reforming (24.9 g/SCF, Table 3) and the remaining refinery hydrogen production underlying the distillates trajectory in Chart 4 from 2026–2050.[1] Total direct *cumulative* emissions prevented could be ~297–400 Mt. *Annual* fuel chain emissions from all distillates in transportation in 2050 (89–91 Mt/y) could be cut by ~12–16%, to ~76–78 Mt/y in the HEFA Case. In the No HEFA Case annual fuel chain emissions from petroleum distillates in 2050 (~22–24 Mt/y) could be cut by ~8–9%, to ~20–22 Mt/y, although use of other biofuels along with ZEVs could add to that 20–22 Mt/y significantly. This measure would be effective in all cases, and far more effective in climate pathways that cap HEFA growth and transition to ZEVs.

4.3.2 <u>Use of electrolysis would facilitate development of hydrogen for potential future use in transportation and energy storage</u>

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
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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. *See* Table 2 below.

Table 2. Hydrogen demand for hydrodeoxygenation (HDO) of HEFA feedstocks, grouped by HDO jet fuel and diesel hydrocarbon yields. Data in kilograms hydrogen per barrel of feed fraction (kg H_2/b)

Feedstock grouping	Jet fraction (C8–C16)[a]		Diesel fraction (C15–C18)[a]		Longer chains (> C18)[a b]	
	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 (10^{th} 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 (90^{th} 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 CO_2 co-production and emission from hydrogen production by steam reforming

3.1.1 How steam reforming makes hydrogen

Steam reforming is a fossil fuel hydrogen production technology that co-produces CO_2. The process reacts a mixture of superheated steam and hydrocarbons over a catalyst to form hydrogen and CO_2. Hydrocarbons used include methane from natural gas, and it is often called steam methane reforming (SMR), but crude refiners use hydrocarbon byproducts from refining such as propane, along with methane from purchased natural gas, as feeds for the steam reformers that they could repurpose for HEFA processing.

3.1.2 How steam reforming emits CO_2

Both its CO_2 co-product and CO_2 formed in its fuel combustion emit from steam reforming. An energy-intensive process, steam reforming burns fuel to superheat process steam and feed, and burns more fuel for energy to drive pumps and support process reactions. Steam reforming fuel combustion emissions are reformer-specific and vary by plant. Based on verified permit data for 11 San Francisco Bay Area crude refinery steam reforming plants, we estimate median fuel combustion emissions of approximately 3.93 grams of CO_2 emitted per gram of hydrogen produced (g CO_2/g H_2), conservatively assuming methane fuel.[2] Co-product emissions are larger still, and vary by feed, with approximately 5.46 g CO_2/g H_2 emitting from methane feed and 6.56 g CO_2/g H_2 emitting from propane feed.[2] The coproduct and combustion emissions are additive.

3.1.3 Steam reforming CO_2 emission estimate

HEFA refinery steam reforming can be expected to use a feed and fuel mix that includes the propane byproduct from the process reactions discussed in Chapter 1 and natural gas methane. Based on process chemistry we conservatively assume 79% methane/21% propane feed with 100% methane fuel. From these figures we estimate typical HEFA steam reforming emissions of approximately 9.82 g CO_2/g H_2. This estimate is for repurposed crude refinery steam reformers, which are aging and may not be as efficient as newer steam reformers.[2] For context, however, our estimate is within 2.5% of a recent independent estimate of median emissions from newer merchant steam methane reforming plants, when compared on a same-feed basis.[2]

Thus, repurposed refinery steam reforming emits CO_2 at nearly ten times its weight in hydrogen supplied. With the high hydrogen demand for HEFA processing shown in Chapter 2, that is a problem. Since steam reforming emissions increase with increased production to meet increased hydrogen demand, the refining CI values reported below are based on the emission factor described above (9.82 g CO_2/g H_2) and the hydrogen demand data from Chapter 2.

3.2 <u>Feedstock effects on CI resulting from HDO hydrogen demand</u>

Hydrodeoxygenation (HDO) is an essential step, and is the major hydrogen consuming step, in all HEFA processing strategies (chapters 1 and 2). The data in Table 4 represent the HEFA processing strategy that uses HDO without intentional hydrocracking (No-IHC).

3.2.1 Feedstock HDO chemistry impact on HEFA refining CI

Table 4 shows effects of feedstock HDO chemistry on HEFA steam reforming emissions. Steam reforming-driven CI (kg/b: kg CO_2 per barrel feed) is substantially higher for whole feeds than for their jet fuel fractions. This is because the non-jet fractions need more hydrogen to saturate carbon double bonds and their combined volumes are larger than that of the jet fuel fraction (tables 1 and 2). Further, the extent of these differences between fractions varies among feeds (*Id.*). This is why feeds change ranks between the columns in Table 4. For example, the jet fuel fraction of palm oil has higher CI than that of soybean oil even though the whole feed data show that soybean oil is a higher CI feed. This variability among feed fractions also is why fish oil CI is high for both the jet fraction and the whole feed.

3.2.2 Need to account for whole feed impact

Does Table 4 show that palm oil could be a higher refining CI feed than soybean oil? No. Since the HDO step is essential for removing oxygen from the whole feed to co-produce both HEFA jet fuel and HEFA diesel, choosing any feed results in the CI impact of that whole feed.

Table 4. Hydrogen steam reforming emissions associated with the jet fuel fraction *v.* whole HEFA feeds in the HDO (No IHC) refining strategy; comparison of feed ranks by emission rate.

Jet fuel fraction (C8–C16)		Whole feed (≥ C8)	
Feed (rank)	CO_2 (kg/b feed)	Feed (rank)	CO_2 (kg/b feed)
Herring oil	46.8	Salmon oil	62.8
Menhaden oil	46.4	Anchovy oil	62.5
Anchovy oil	46.4	Tuna oil	61.7
Tuna oil	45.9	Menhaden oil	60.7
Poultry fat	45.0	Soybean oil	55.8
Tallow fat	44.5	Distillers corn oil	54.8
UCO (10th Percentile)	44.4	UCO (90th Percentile)	54.4
Salmon oil	44.3	Herring oil	54.0
Lard fat	43.5	Cottonseed oil	53.4
Palm oil	43.0	Canola oil	53.1
Canola oil	42.7	Poultry fat	49.4
UCO (90th Percentile)	42.7	UCO (10th Percentile)	49.2
Cottonseed oil	42.2	Lard fat	47.6
Soybean oil	42.0	Palm oil	47.1
Distillers corn oil	41.9	Tallow fat	46.2

C8–C16: fatty acid chains with 8 to 16 carbon atoms. **≥ C8:** fatty acid chains with 8 or more carbon atoms. **Menhaden:** a fish. **UCO:** used cooking oil, a variable feed; 10th and 90th percentiles shown. Data from Table 2 at 9.82 g CO_2/g H2 steam reforming.

While the jet fuel fraction data in this table helps to inform why feed quality impacts refining CI, we need to account for those CI impacts of whole feeds shown in Table 4.

3.2.3 High-jet feeds can increase or decrease HDO-driven CI

HDO-driven CI findings for whole feeds reveal mixed CI results for high-jet fuel yield feedstocks in No-IHC processing. Fish oils rank highest for steam reforming-driven CI while livestock fats and palm oil rank lowest (Table 4). Thus, for this processing strategy, switching feeds to boost jet fuel yield can increase or decrease refining CI. However, No-IHC also is the processing strategy that HEFA refiners use to maximize diesel yield rather than jet fuel yield. Feedstock quality interacts with other processing choices in different ways that could further boost HEFA refining CI along with jet fuel yield, as shown below.

3.3 Feedstock effects on CI resulting from Selective-IHC hydrogen demand

3.3.1 Process strategy impact of high-jet feeds

High jet yield feeds result in less input to Selective-IHC, enabling marginally hydrogen-limited refiners to further boost jet fuel yield via Selective-IHC, but this requires additional hydrogen (chapters 1 and 2). Intentional hydrocracking (IHC) thus increases hydrogen steam reforming rates and emissions, increasing refining CI for all feeds, as shown in Table 5. This impact overlies the HDO impact, so that feed CI values overlap between columns. For example, the tuna oil No-IHC CI (61.7 kg/b) exceeds the tallow Selective-IHC CI (60.0 kg/b), and the anchovy oil Selective-IHC CI (75.3 kg/b) exceeds the soy oil Isom-IHC CI (73.9 kg/b).

Table 5. Hydrogen steam reforming emissions from the No-IHC, Selective-IHC, and Isomerization IHC refining strategies: comparisons of whole HEFA feed ranks by emission rate.

No-IHC		Selective-IHC		Isomerization-IHC	
Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)
Salmon oil	62.8	Salmon oil	76.4	Salmon oil	81.0
Anchovy oil	62.5	Anchovy oil	75.3	Anchovy oil	80.8
Tuna oil	61.7	Tuna oil	74.8	Tuna oil	80.1
Menhaden oil	60.7	Soybean oil	72.0	Menhaden oil	78.8
Soybean oil	55.8	Menhaden oil	71.6	Soybean oil	73.9
Corn oil–DCO	54.8	Corn oil-DCO	70.6	Corn oil-DCO	72.8
UCO 90th P.	54.4	UCO 90th P.	70.4	UCO 90th P.	72.6
Herring oil	54.0	Canola oil	70.3	Herring oil	72.0
Cottonseed oil	53.4	Cottonseed oil	67.2	Cottonseed oil	71.5
Canola oil	53.1	Herring oil	66.4	Canola oil	71.1
Poultry fat	49.4	UCO 10th P.	62.5	Poultry fat	67.2
UCO 10th P.	49.2	Poultry fat	61.7	UCO 10th P.	67.1
Lard fat	47.6	Lard fat	60.2	Tallow fat	65.7
Palm oil	47.1	Tallow fat	60.0	Lard fat	65.3
Tallow fat	46.2	Palm oil	56.9	Palm oil	64.8

IHC: Intentional hydrocracking. **No-IHC:** CO_2 from hydrodeoxygenation (HDO). **Selective-IHC:** CO_2 from HDO plus IHC of HDO output hydrocarbons > C16. **Isomerization-IHC:** CO_2 from HDO plus IHC of all HDO output (> C8). **Menhaden:** a fish. **UCO:** used cooking oil, 10th, 90th percentiles shown. **DCO:** distillers corn oil. Figures shown exclude emissions associated with H_2 losses, depropanation, and inadvertent cracking. Data from Table 3 at 9.82 g CO2/g H2 steam reforming.

3.3.2 Feed chemistry effects on feed rankings for CI

Feedstock CI rankings differ between No-IHC and Selective-IHC processing (Table 5). This is a feed quality impact driven primarily by the different volumes of non-jet fractions sent to IHC among feeds. It boosts the CI of soybean oil from 4.9 kg/b below to 0.4 kg/b above the CI of menhaden oil with the addition of Selective-IHC (*Id.*). With 88.3% of its volume outside the jet fuel range compared with 57.7% of menhaden oil (Table 1, > C16 fractions), soy oil sends 30.6% more feed to Selective-IHC than menhaden oil. More IHC feed requires more hydrogen, boosting steam reforming emissions more with soy than with menhaden oil. Similarly, canola oil sends 27.9% more feed to Selective-IHC than herring oil (*Id.*). This boosts canola oil CI from 0.9 kg/b below to 3.9 kg/b above herring oil CI with the addition of Selective-IHC (Table 5).

3.3.3 How livestock fat feeds could affect soy oil and canola oil refining CI

When switching from soy or canola oil to livestock fat enables a refiner to boost jet fuel yield by repurposing its refinery for Selective-IHC processing, that intentional hydrocracking can boost jet yield from soy and canola oil feeds as well. Thus, instead of shutting down when, for any reason at any time, livestock fat becomes too scarce or expensive, the refiner could make jet fuel by going back to soybean oil or canola oil feedstock. This could increase refining CI by 16.2 kg/b (29%) for soy oil, and 17.2 kg/b (32%) for canola oil, based on our results for the Selective-IHC *versus* No-IHC processing strategies in Table 5.

3.4 Feedstock effects on CI resulting from Isom-IHC hydrogen demand

Livestock fat and palm oil could maximize jet fuel yield by enabling Isom-IHC processing, since these feeds minimize HDO hydrogen demand (chapters 1 and 2). Their relatively lower non-jet fractions do not contribute to this effect on Isom-IHC because, in contrast to Selective-IHC, Isom-IHC processes the entire feed stream output from HDO. Direct effects of feed quality variability on Isom-IHC cracking are relatively weak, since HDO both saturates and removes oxygen from Isom-IHC inputs. Thus, the relative feed rankings for CI from No-IHC processing carry over to the Isom-IHC feed rankings with only minor differences (Table 5). However, by cracking of the entire HDO output, Isom-IHC further boosts hydrogen demand, thus hydrogen steam reforming emissions, resulting in the highest HEFA refining CI for all feeds (*Id.*).

Across feeds and process options, from the lowest to the highest impact combinations of feeds and processing, HEFA refining CI increases by 34.8 kg CO_2/b (75%), and CI increases in 122 (79.7%) of 153 feed switching combinations that could boost jet fuel yield (tables 1, 3, 5).

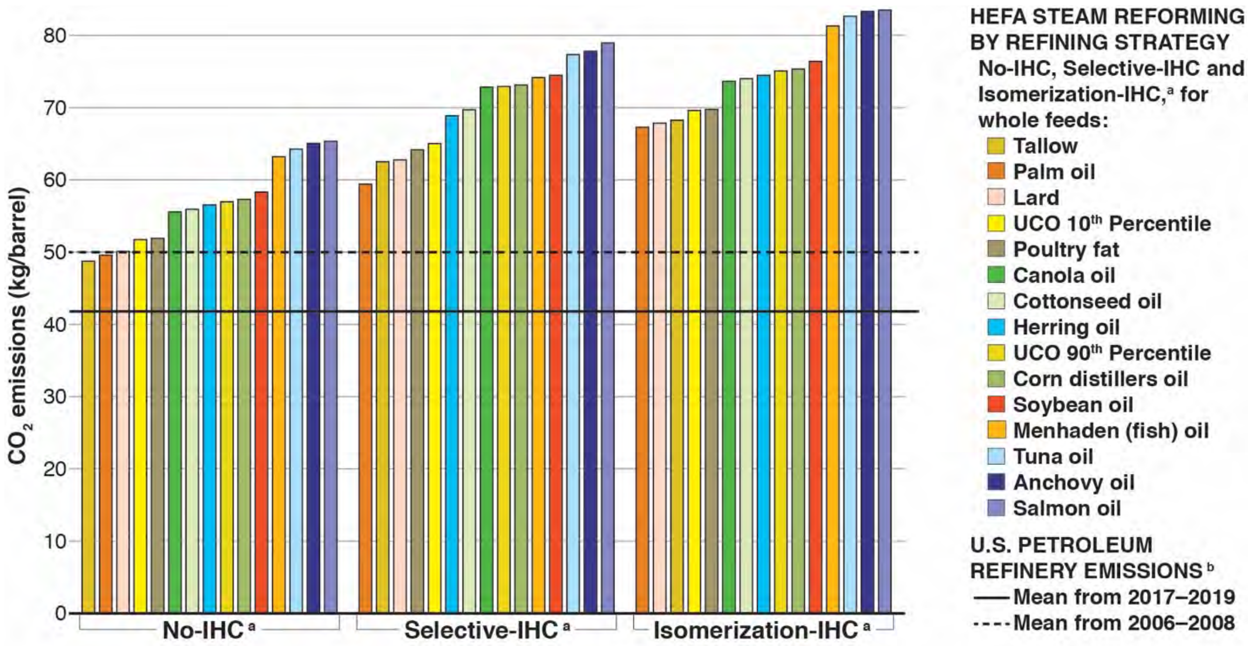
3.5 Comparison with petroleum refining CI by feedstock and processing strategy

Chart 1 plots results for feedstock-related impacts on the variability of HEFA refining CI from HEFA steam reforming emissions against the CI of U.S. petroleum refining. Our results in Table 5 are shown by processing strategy and, within each strategy, each feed is represented by a color-coded column. The height of the column represents the contribution of steam reforming to HEFA refining CI for that particular feed and processing strategy. The solid black line shown at approximately 41.8 kg/b (kg CO_2/barrel crude processed) represents the average U.S. petroleum refining CI from 2015 through 2017.[6] We use this (41.8 kg/b) as our benchmark. For added context, average U.S. petroleum refining CI from 2006–2008,[7] a period when the U.S. refinery crude slate was denser and higher in sulfur than during 2015–2017[8] resulting in higher historic U.S. crude refining industry CI,[7] is represented by the dashed line at 50 kg/b in the chart.

Please note what HEFA emissions Chart 1 does and does not show. It shows HEFA refining steam reforming emissions only. This helps us focus on our question about refining CI impacts from HEFA feedstock switching to target jet fuel, which are directly related to HEFA steam reforming rates. It *does not* show total direct emissions from HEFA refining.

3.5.1 HEFA refining CI impacts are significant compared with crude refining

Other HEFA refining emissions besides those from steam reforming—from fuel combustion to heat and pressurize HEFA hydro-conversion reactors, precondition and pump their feeds, and distill and blend their products—could add roughly 21 kg/b of additional HEFA refining CI.[2] Thus, for a rough comparison of petroleum refining CI with total HEFA refining CI, imagine adding 21 kg/b to the top of each column in Chart 1. HEFA refining CI approaches or exceeds *double* the CI of petroleum refining. Clearly, expanding HEFA jet fuel would increase the CI of hydrocarbon fuels processing substantially.



1. HEFA Steam Reforming Emissions *v.* Total U.S. Petroleum Refining Emissions, kg CO_2/barrel feed input.

a. HEFA steam reforming emissions only: values shown exclude CO_2 emitted by other HEFA refining process and support equipment. This contrasts with the petroleum refining emissions shown, which include all direct emissions from crude refining. Including all direct emissions from HEFA refining could increase the HEFA estimates shown by approximately 21 kg/barrel.[2] The "No-IHC" strategy excludes intentional hydrocracking (IHC); the "Selective-IHC" strategy adds emission from producing hydrogen consumed by intentional hydrocracking of feed fractions comprised of hydrocarbons outside the jet fuel range; the "Isomerization-IHC" strategy adds emissions from intentional hydrocracking of whole feeds in the isomerization step of HEFA fuels production. HEFA data shown include feed-driven emissions in Table 5 plus additional steam reforming emissions (2.5 kg/b) from producing the additional hydrogen that is lost to unintended side-reaction cracking, solubilization, scrubbing and purging (*see* Table 8).[1]

b. U.S. petroleum refinery emissions including total direct CO_2 emitted from steam reforming and all other petroleum refinery process and support equipment at U.S. refineries. Mean from 2015 through 2017 based on total refinery emissions and distillation inputs reported by the U.S. Energy Information Administration (EIA).[6] Mean from 2006 through 2008 represents a period of historically high-carbon U.S. refining industry crude inputs.[7 8]

3.5.2 High-jet feed impacts on processing targeting jet fuel can increase refining CI

Feeds that enable intentional hydrocracking to boost jet fuel yield could increase HEFA refining CI significantly (Chart 1). Here we report feed switching CI increments compared with No-IHC processing of soy and canola oils to target diesel yield (*see* Table 5) as percentages of our petroleum crude refining benchmark: Switching to Selective IHC with anchovy and salmon oils increases CI by 47% to 56% (of crude refining CI) while switching to Selective IHC with menhaden oil increases CI by 38% to 44%. Switching to Isom-IHC with tallow increases CI by 24% to 30% while switching to Isom-IHC with palm oil increases HEFA refining CI by 21% to 28% of crude refining CI. Switching to Selective-IHC with tallow increases CI by 10% to 17%. Only Selective-IHC with palm oil has similar CI to that of No-IHC with soy oil (+3%).

3.5.3 High-jet feed CI impacts are mixed in processing targeting HEFA diesel yield

Compared with No-IHC processing of soy or canola oils, which are the combinations of processing and feeds that maximize HEFA diesel yield, No-IHC with fish oils could increase refining CI while No-IHC with palm oil or livestock fats could decrease CI. For example, switching to anchovy oil could increase No-IHC HEFA refining CI over that of canola and soy oils by 16% to 23% of crude refining CI while switching to tallow could decrease it by 16% to 23% of crude refining CI. But there is a caveat to those estimates.

In theory, feeding tallow to No-IHC processing could boost jet fuel yield to one-third of feedstock volume (Table 1) while lowering CI by 6.8 or 9.5 kg/b below canola or soy oil in No-IHC processing, the strategies refiners use to maximize HEFA diesel yield. However, this would require three barrels of tallow feed per barrel of jet fuel yield, emphasizing a crucial assumption about HEFA biofuel as a sustainable jet fuel solution—it assumes a sustainable feedstock supply. That assumption could prove dangerously wrong, as shown in Chapter 4.

4. HEFA jet fuel feedstock and carbon sinks: Could the feedstocks that maximize HEFA jet fuel instead of diesel yield have comparatively high indirect climate impacts?

Increasing demand for limited supplies of feedstocks that refiners could use to boost HEFA jet fuel yield and make more HEFA jet fuel risks increasing deforestation and other serious indirect climate impacts. HEFA biofuel feedstocks are purpose-derived lipids also needed for food and other uses,[9 10] are globally traded, and can increase in price with increased biofuel demand for their limited supply.[2] Ecological degradation caused by expanded production and harvesting of the extra lipids for biofuels has, in documented cases, led to emissions from natural carbon sinks due to biofuels. Those emissions have traditionally been labeled as an "indirect land use impact," but as shown above, refiners seeking to maximize HEFA jet fuel production also could use fish oil feedstocks. The term "indirect carbon impacts," meant to encompass risks to both terrestrial and aquatic carbon sinks, is used in this chapter.

4.1 <u>Natural carbon sinks that HEFA jet fuel feedstock acquisition could affect</u>

Feedstocks that increase HEFA jet fuel production could have indirect impacts on land-based carbon sinks, aquatic carbon sinks, or both. At the same time the impact mechanisms differ between terrestrial and aquatic ecosystems. Part 4.1.1 below discusses carbon sink risks due to land degradation, and part 4.1.2 discusses carbon sink risks due to fishery depletion.

4.1.1 Land degradation risks: Carbon sinks in healthy soils and forests

Even before new Sustainable Aviation Fuel plans raised the potential for further expansion of HEFA feedstock acquisition, biofuel demand for land-based lipids production was shown to cause indirect carbon impacts. A mechanism for these impacts was shown to be global land use change linked to prices of commodities tapped for both food and fuel.[11] Instead of cutting carbon emissions, increased use of some biofuel feedstocks could boost crop prices, driving crop and pasture expansion into grasslands and forests, and thereby degrading natural carbon sinks to result in biofuel emissions which could exceed those of petroleum fuels.[11]

Indirect carbon impacts of lipid feedstocks which further HEFA biofuel expansion could tap have been observed and documented in specific cases. International price dynamics involving palm oil, soybean oil, biofuels and food were linked as factors in the deforestation of Southeast Asia for palm oil plantations.[12] Soy oil prices were linked to deforestation of the Amazon and Pantanal in Brazil for soybean plantations.[13 14 15] Demand-driven changes in European and U.S. prices were shown to act across the oil crop and animal fat feedstocks for HEFA biofuels.[16] Rapeseed (canola) and soy biofuels demand drove palm oil expansion in the Global South as palm oil imports increased for other uses of those oils displaced by biofuels in the Global North.[17] Indirect land use impacts of some soy oil—and most notably, palm oil—biofuels were found to result in those biofuels emitting more carbon than petroleum fuels they are meant to replace.[17 18 19] Current U.S. policy discourages palm oil-derived biofuel for this reason.[20]

As of 2021, aerial measurements suggest that combined effects of deforestation and climate disruption have turned the southeast of the great Amazonian carbon sink into a carbon source.[21] Market data suggest that plans for further HEFA biofuels expansion have spurred an increase in soybean and tallow futures prices.[22 23 24] A joint report by two United Nations-sponsored bodies, the Intergovernmental Panel on Climate Change and the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services, warns that expansion of industrial biofuel feedstock plantations risks inter-linked biodiversity and climate impacts.[25]

Moreover, these risks are mutually reinforcing. Potential pollinator declines,[26] climate heating-driven crop losses,[27] biofuel policy-driven food insecurity,[28] and the prospect that, once a biofuel also needed for food is locked into place, retroactive limits on land use conversion could worsen food insecurity,[11] reveal another aspect of this carbon sink risk. Namely, the assumption asserted by HEFA biofuel proponents, that we can "grow our way out" of limits on biomass diversion to biofuels by increasing crop yields and reverse course later if that does not work, risks lasting harm.

4.1.2 Fishery depletion risks: The biological carbon pump in world oceans

Increasing demand for fish products could further drive fisheries depletion, thereby risking substantial emissions from the oceanic carbon sink. This potential impact, like that on terrestrial carbon sinks, has received intensifying scientific attention in recent years, but appears to remain less widely known to the general public. Fished species have crucial roles in the mechanisms that send carbon into the oceanic carbon sink, as shown below.

Oceans account for 71% of the Earth surface[29] and remove roughly one-fourth to one-third of total carbon emissions from all human activities annually.[30 31] A portion of the CO_2 exchange between air and water at the sea surface is sequestered in the deep seas via inter-linked shallow, mid-reach, and benthic ecosystems that comprise a "biological pump" in which fished species play key roles. See Illustration 1.

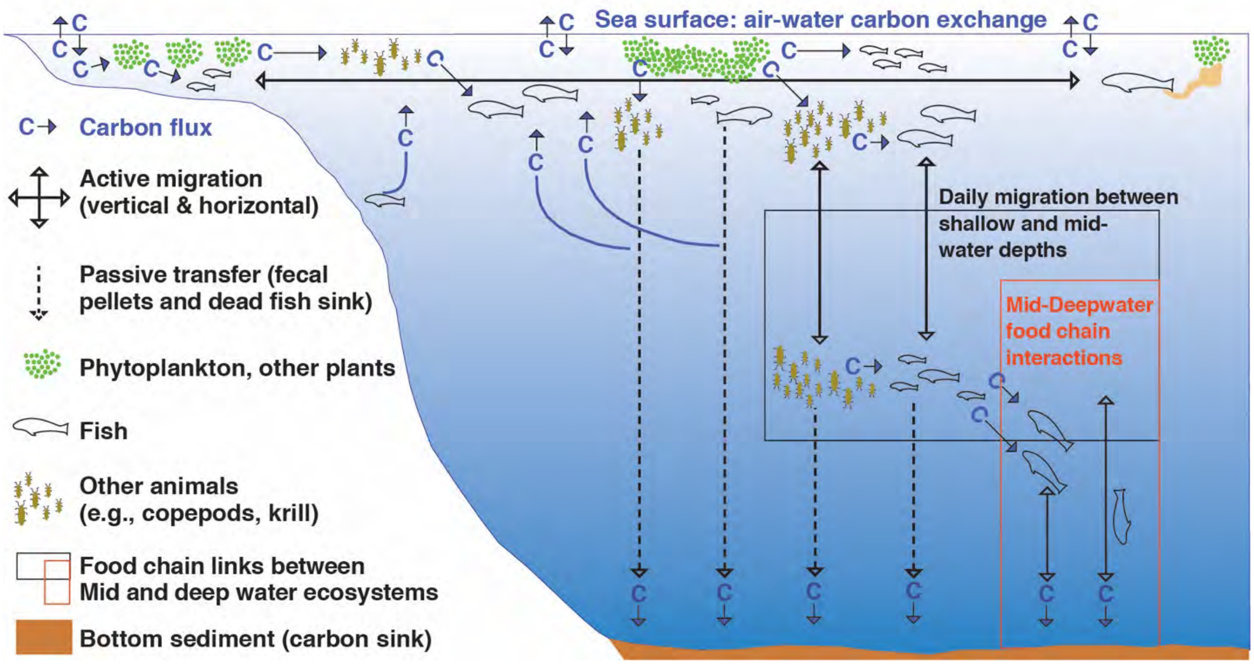


Illustration 1. Biological pump to the deep oceans carbon sink

Fish have key roles in the inter-linked shallow, mid-reach, and benthic ecosystems that drive a "biological pump" which sends carbon into the deep seas. In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants, then by animals in aquatic food webs, and horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake. Some of this carbon falls to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown), while respiration releases CO_2 from aquatic animals and from bacterial degradation of fecal matter (upward-curving lines), some of which re-enters the atmosphere at the sea surface. Active vertical migration (solid vertical lines) further drives the biological pump. A substantial portion of both fish and their invertebrate prey biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight—where deep-sea fish species migrate and feed as well (black and red boxes). Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea. The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.

In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants and then by animals in ocean food webs. (Illustration, top.) Horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake (*Id.*).[25 31] Some of this carbon sinks to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown)[25 32] but not all of it; some of the CO_2 released in respiration by aquatic animals and bacterial degradation of fecal matter re-enters the atmosphere at the sea surface (upward-curving lines).[30 32] That sea surface carbon exchange emphasizes the role of active vertical migration (solid vertical lines) in the biological pump.

For both fish and their invertebrate prey, a substantial portion of their ocean biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight[25]—where deep-sea fish species migrate and feed as well.[32] Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea.[25 30 32] The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.[25 30 32]

Although impacts are not yet fully quantified,[25] at present—even at "maximum sustainable yield"—fishery depletion impacts the oceanic carbon sink by removing roughly half of the fisheries biomass that would otherwise be in world oceans.[25 31] This exports the carbon in fish from ocean sequestration to land, where that exported carbon then enters the atmosphere.[25 31] Fished species are targeted selectively, disrupting ecosystems involved in the biological pump and potentially reducing both the passive and the active transport of carbon to deep sea carbon sequestration.[25 32] Worse, as demands for limited fisheries catches have grown, bottom trawling, which directly disrupts and releases carbon from ocean sediments, may already have reduced the oceanic carbon sink by as much as 15–20%.[25] In this context fish oil demand, while only a small fraction of total fisheries catch, is still supplied more from whole fish than from fish byproducts, and is projected to grow by a few percentage points through 2030.[10] Thus, potential additional fish oil demand for biofuel poses an indirect carbon impact risk.

4.2 <u>Historic impact assessments for high jet fuel yield HEFA feedstocks</u>

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. <u>*See*</u> 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. <u>*See*</u> 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 Priorities for future work

5.2.1 Cellulose biomass alternatives—what is holding them back?

Cellulosic residue biomass such as cornstalks, currently composted yard cuttings, or sawdust can be used as feedstock by alternative technologies which qualify as SAF.[19 35] Using this type of feedstock for SAF could lessen or avoid the indirect carbon impacts from excessive HEFA jet fuel demand for limited lipids biomass that are described in Chapter 4. Indeed, economy-wide analyses of the technologies and measures to be deployed over time for climate stabilization suggest prioritizing cellulosic biomass, to the extent that biofuels will be needed in some hard-to-decarbonize sectors.[42 57 58] Despite its promise, however, the deployment of cellulosic distillate biofuel has stalled compared with HEFA biofuel. Less clear are the key barriers to its growth, the measures needed to overcome those barriers, and whether or not those measures and the growth of cellulosic jet fuel resulting from them could ensure that SAF goals will be met sustainably. This points to a priority for future work.

5.2.2 Alternatives to burning jet fuel—need and potential to limit climate risks

Even complete replacement of petroleum jet fuel with SAF biofuel combustion would result in ongoing aviation emissions, and would thus rely on additional and separate carbon capture-sequestration to give us a reasonable chance of stabilizing our climate. At the current jet fuel combustion rate the scale of that reliance on "negative emission" technologies, which remain unproven at that scale, is a risky bet. Meanwhile, besides alternative aircraft propulsion systems, which are still in the development stage, there are alternatives to jet fuel combustion which are technically feasible now and can be used individually or in combination.

Technically feasible alternatives to burning jet fuel include electrified high-speed rail, fuel cell powered freight and shipping to replace air cargo, and conservation measures such as virtual business meetings and conserving personal air-miles-traveled for personal visits. While we should note that such travel pattern changes raise social issues, so does climate disruption, and most people who will share our future climate are not frequent fliers. Importantly as well, public acceptance of new travel alternatives is linked to experiencing them. Thus, biofuel limitations, climate risks, and human factors suggest needs to prioritize the development and deployment of alternatives to petroleum jet fuel that do not burn carbon.

5.2.3 Limited safety data record for flying with new fuels

Jet biofuels appear to differ from petroleum jet fuels in their cold flow properties at high altitude, combustion properties, and potential to damage fuel system elastomer material.[19] Those that can be used as SAF have been approved subject to blending limits, which permit SAF to be "dropped-in" to conventional jet fuel up to a maximum of 50% of the blend.[59] All seven types of biofuels approved for SAF are subject to this condition.[59] SAF/petroleum jet fuel blends that do not meet this condition are deemed to present potential safety issues.[59]

However, remarkably limited historical use of SAF (§4.3.1) has resulted in a limited data record for assessing its safety in actual operation. That is important because new hazards which result in dangerous conditions over long periods of operation have repeatedly been discovered only by rigorous post-operational inspection or post-incident investigation, the histories of both industrial and aviation safety oversight show. There is an ongoing need to ensure flight safety risks of biofuels are closely monitored, rigorously investigated, transparently communicated, and proactively addressed by "inherent safety measures"[60] designed to eliminate any specific hazards identified by that future work.

Table 8. Data and methods table for feed-specific estimates.[a]

Fatty acid (FA) in HEFA oil feed				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-γ-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.

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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						
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	10^{th} Percentile	25^{th} Percentile	75^{th} Percentile	90^{th} 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
Martinez Refinery Renewable Fuels Project
Draft Environmental Impact Report, County
File: # CDLP20-02046
State Clearinghouse No. 2021020289

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 Martinez Refinery Renewable Fuels Project ("project"). The project would, among other things, repurpose selected petroleum refinery process units and equipment from the shuttered Marathon Martinez 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

[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. 2-16 ("hydrogen plants at the Refinery would provide hydrogen to the Hydrotreating and Hydrocracking Units to support the hydrodeoxygenation (HDO) and isomerization reactions required" to make renewable fuels).

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

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[8] DEIR Table 2-1 (new or repurposed equipment to gasify biomass excluded).
[9] DEIR p. 2-1 (proposed project would "switch to ... feedstock sources including rendered fats, soybean and corn oil, and potentially other cooking and vegetable oils ...").
[10] Karras, 2021a (Att. 2).
[11] *Id.*
[12] *Id.*
[13] *Id.*

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 describe the technology used by existing onsite hydrogen plants proposed to be repurposed by the project. These hydrogen plants use fossil fueled hydrogen steam reforming technology. This fossil gas steam reforming would co-produce roughly ten tons of carbon dioxide (CO_2) emission with each ton of hydrogen supplied to project biofuel processing,[15] but the basis for knowing to evaluate that potential impact is obscured by omission in the DEIR.

The DEIR identifies a non-fossil fuel hydrogen production technology—splitting water to co-produce hydrogen and oxygen using electricity from renewable resources—then ranks its impacts in relation to the project with fossil gas steam reforming without describing either of those hydrogen alternatives adequately to support 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 those hydrocarbons so that they can be burned as diesel or jet fuel.[18] Except for naming the two separate processing steps that would use hydrogen in repurposed refinery hydro-conversion process units to deoxygenate the feed (hydrodeoxygenation) and restructure the deoxygenated hydrocarbons (isomerization), the DEIR does not describe the project biofuel processing chemistry or reaction conditions. The DEIR thus does not describe environmentally significant differences in HEFA refining compared with petroleum refining, impacts of feed choices and product targets in project biofuel processing, or changes in the process conditions of repurposed refinery hydro-conversion 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

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

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 be boosted to roughly 50% on HEFA feed mass, by 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 <u>Relationships between feedstock choices, product targets and hydrogen inputs</u>

HEFA process hydrogen demand exceeds that of petroleum refining by a wide margin generally, however, 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 48,000 b/d capacity 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)

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[25] *Id.*
[26] Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[27] DEIR p. 2-1 (proposed project would “switch to ... feedstock sources including rendered fats, soybean and corn oil, and potentially other cooking and vegetable oils ...”).
[28] Karras, 2021b (Att. 3).
[29] *Id.*
[30] *Id.*

impacts estimated above could result in emission increments of 168,000, 342,000, and 485,000 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.[31] Most significantly, even the low end of the emissions range for combined feed choice and 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%).[32] [33]

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.[34] 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.[35] 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.[36] 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.

[31] HEFA emission estimates based on per-barrel steam reforming CO_2 emissions from Table 5 in Attachment 3.
[32] *Id.*
[33] Average U.S. petroleum refining carbon intensity from 2015–2017 of 41.8 kg CO_2/b crude from Attachments 2, 3.
[34] Karras, 2021a (Att. 2).
[35] *Id.*
[36] *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[37] and to create new and different process hazards[38] [39] and feedstock acquisition impacts.[40] 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 <u>Change and variability in feedstock chemistry and processing characteristics</u>

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.[41] 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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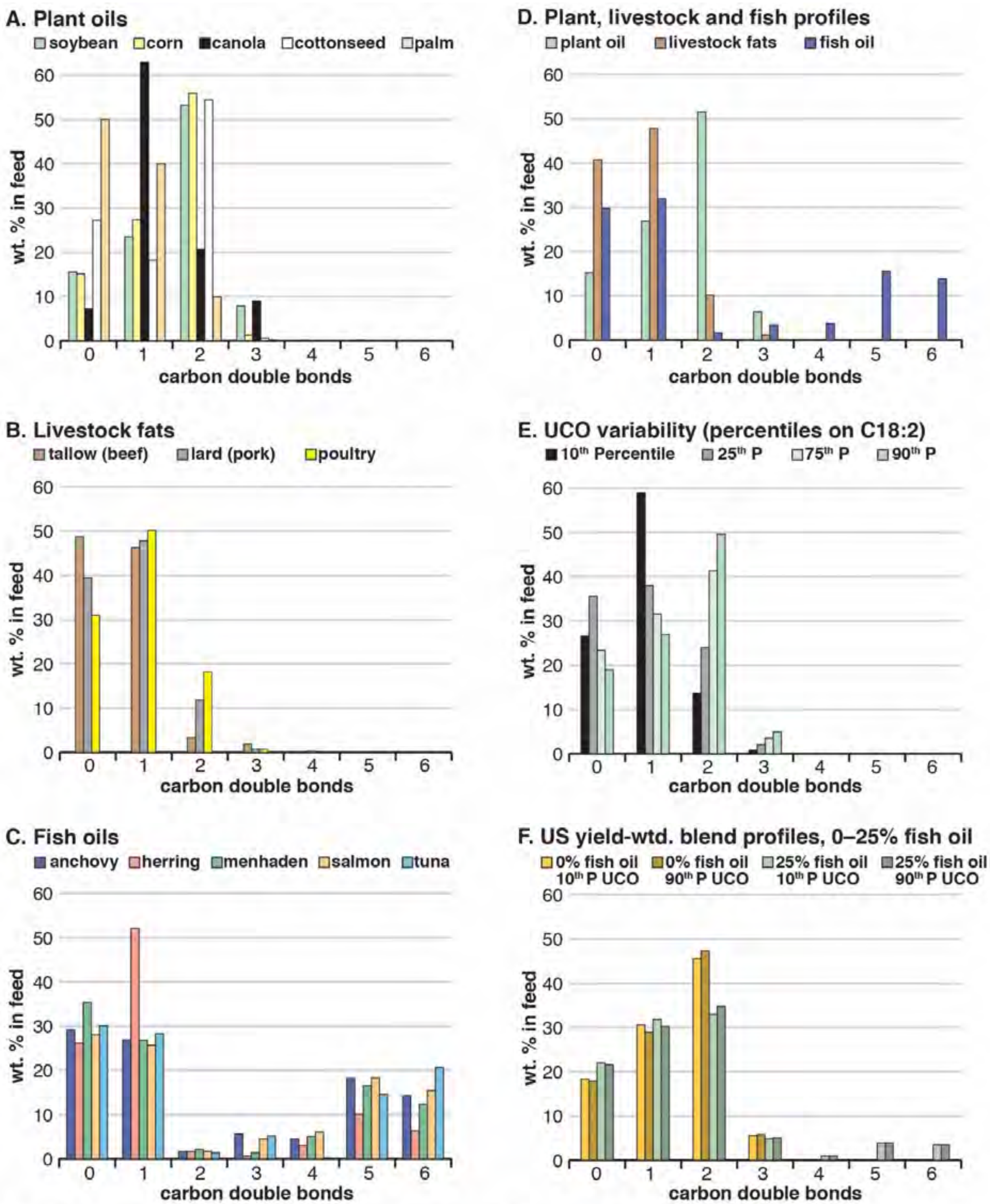
[37] <u>See</u> Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.
[38] <u>See</u> CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S. Chemical Safety Board: Washington, D.C. https://www.csb.gov/file.aspx?Documentid=5913. Appended hereto as Attachment 7.
[39] <u>See</u> 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.
[40] <u>See</u> 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.
[41] <u>See</u> 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.[42] 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 the project could become among the largest HEFA refineries to be built worldwide—second perhaps only to the concurrently proposed HEFA conversion project in nearby Rodeo.[43]

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 48,000 b/d (approximately 2.55 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 Phillips 66 in Rodeo, 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.[44] These existing uses represent commitments of finite resources, notably cropland, to human needs. Used cooking oils derived from primary sources shown are similarly spoken for and in even shorter supply. Lastly, HEFA feeds are limited to lipids (shown) while most other biofuels are not, but multiple other HEFA refineries are operating or proposed besides the two Contra Costa County projects shown.

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[42] *See* Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[43] Karras, 2021a (Att. 2).
[44] 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) Marathon Project [b]	Phillips 66 Project [b]	Both Projects
Fish oil	0.13	1961 %	3269 %	5231 %
Livestock fat	4.95	51 %	86 %	137 %
Soybean oil	10.69	24 %	40 %	64 %
Other oil crops	5.00	51 %	85 %	136 %
Total yield	20.77	12 %	20 %	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 2.55 MM t/y (48,000 b/d from DEIR), related project demand of 4.25 MM t/y (80,000 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.[45] 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.[46] 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.

[45] Data in Table 1 thus rebut the unsupported DEIR assertion that future project feeds are wholly speculative.
[46] *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.[47] 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,[48] which include phasing out petroleum and biofuel diesel in favor of zero-emission vehicles.

1.6 Project Fuels Market

Potential interactions between the project and the liquid combustion fuels market in California are described in the DEIR,[49] however, it describes potential impacts resulting from imports while omitting any discussion of exports from California refineries or the conditions under which these exports could occur. That description is incomplete and inaccurate. California refineries are net fuel exporters due in large part to structural conditions of statewide overcapacity coupled with declining in-state petroleum fuels demand.[50] [51] [52] The incomplete description of the project fuels market setting can lead to flawed environmental impacts evaluation, as discussed in §§ 2 and 5.

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[47] 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.
[48] Karras, 2021a (Att. 2).
[49] DEIR pp. 2-17, 3-3, 3-6, 3.6-9, 3.8-13, 3.9-16, 4-12, 5-4, 5-13.
[50] Karras, 2020 (Att. 10).
[51] 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.
[52] 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 describe or disclose a project component that would build intentional hydrocracking capacity into the project to enable increasing HEFA jet fuel production. The 1st Stage Hydrocracker would be repurposed for intentional hydrocracking, unlike the 2nd Stage Hydrocracker, which would be repurposed for isomerization.[53] Unlike that isomerization unit and the #2 and #3 hydro-deoxygenation units, the 1st Stage Hydrocracker could crack up to 24,000 b/d of fresh feed and could not operate independently.[54] This would transform the HEFA refinery into a "Selective Intentional Hydrocracking" configuration that could boost jet fuel yield from roughly half of total project feedstock, and boost it from as little as 13% to as much as 49% by mass on that half of the project feedstock.[55] But in doing so, this hydrocracking-to-boost-jet-yield component would increase refinery hydrogen and resultant project impacts.[56]

The undisclosed project component would be interdependent with disclosed components of the project. The intentional hydrocracking would depend on the project feed acquisition, feed pretreatment, hydrodeoxygenation, and isomerization infrastructure proposed, without which it could not proceed.[57] Disclosed project components, in turn, would depend upon this undisclosed component to boost jet fuel yield and maintain the viability of the biorefinery. In fact boosting the very low jet yield in the absence of intentional cracking[58] could well be a "stay in business" need for the refinery as more efficient battery-electric and fuel-cell-electric vehicles[59] phase out diesel in favor of zero-emission vehicles (ZEVs) pursuant to California state plans and policies.[60]

Crucially, the equipment modifications to implement this hydrocracking-to-boost-jet-yield component are included in the project,[61] but instead of disclosing and describing it for review, the DEIR frames the "potential" for the project to target jet fuel as only an afterthought.[62]

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[53] DEIR pp. 2-20, 2-21; Table 2-1. Refinery Equipment Modifications.
[54] *Id.*
[55] *See* process description data in Karras, 2021b (Att. 3).
[56] *Id.*
[57] *Id.*
[58] *Id.*
[59] *See* Karras, 2021a (Att. 2).
[60] *Id.*
[61] DEIR pp. 2-20, 2-21; Table 2-1. Refinery Equipment Modifications.
[62] DEIR p. 6-3 ("The Project would convert ... to the production of renewable fuels, including renewable diesel, renewable propane, renewable naphtha *and potentially renewable jet fuel" [emphasis added]*).

CONCLUSION: The DEIR provides an incomplete, inaccurate, and truncated or at best unstable 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. 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[63] emissions. The DEIR improperly concludes that the project would decrease net GHG emissions[64] 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."[65] 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[66] and total distillates—petroleum distillates and diesel biofuels—burned in California.[67] 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,

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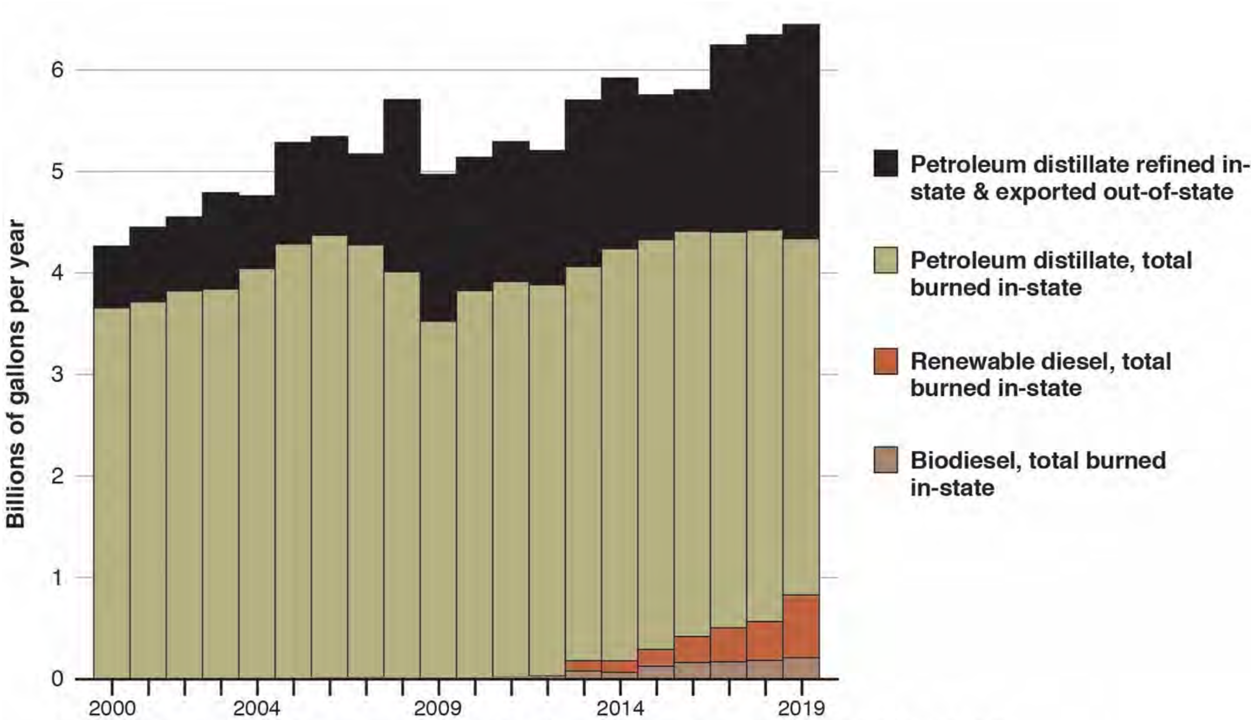
[63] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[64] "Project would result in an overall decrease in emissions ... [including] indirect GHG emissions" (DEIR p. 3.8-20) and "GHG emissions from stationary and mobile sources" (DEIR p. 3.8-22).
[65] CCR §§ 38505 (j), 38562 (b) (8).
[66] 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 13.
[67] 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 14.

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.[68] [69]



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. 13) and CARB GHG Inventory (Att. 14).

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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[68] *Id.*
[69] CEC Fuel Watch (Att. 13).

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 describes potential GHG emissions resulting from imports for the proposed project[70] while ignoring fuels exports from California 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.[71] Importantly, before diesel biofuel addition further increased refining of petroleum distillates for export, the structural overcapacity of California refineries was evident from the increase in their exports after in-state demand peaked in 2006. *See* Chart 2 above. California refining capacity, especially, is overbuilt.[72] 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.[73] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[74] *See* Table 2.

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

Total volumes reported for ten-year periods

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

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

70 DEIR p. 4-12
71 USEIA, 2015 (Att. 11).
72 Karras, 2020 (Att. 10).
73 *Id.*
74 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[75] approached the range of interannual variability from 2012–2019 for gasoline and reached the low end of this pre-COVID range in July, while taxable jet fuel and diesel sales exceeded the maximum or median of the 2012–2019 range in each month from April through July of 2021. <u>*See*</u> Table 3.

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

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

	Demand in 2021	Pre-COVID range (2012–2019) Minimum	Median	Maximum	Comparison of 2021 data with 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. 15). 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.

[75] 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 15.

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.[76] *See* Table 4. 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.[77] 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

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

Data 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.

[76] USEIA, *Supply and Disposition* (Att. 12).
[77] *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. 13. Statewide refinery capacity as of 1/1/21, after the Marathon Martinez refinery closure, from Att. 16. 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).[78] [79] [80] Moreover, review of Table 5 reveals 222,000 b/d to more than 305,000 b/d of spare California refinery capacity during this fuels demand rebound.

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

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

Utilization of operable capacity in barrels/calendar day from Att. 17. 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.

[78] CEC Fuel Watch (Att. 13).
[79] USEIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity. Appended hereto as Attachment 16.
[80] USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Inf. Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm Appended hereto as Attachment 17.

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 San Francisco Refinery.[81] The project would worsen this growing condition of overcapacity that drives refined fuels export emission-shifting by producing and selling even more 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, providing "renewable" fuels production for the California market is a project objective.[82] The DEIR, however, does not disclose or evaluate this causal factor for the observed emission-shifting impact of recent "renewable" diesel additions.

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

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

Accounting for yields on feeds targeting renewable diesel[83] and typical feed and fuel densities shown in Table 7, operating at its 48,000 b/d the project could make approximately 1.62 million gallons per day of renewable diesel, resulting in export of the equivalent petroleum distillates

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[81] 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. 16).
[82] DEIR p. 2-2.
[83] 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 18.

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.[84]

The net emission shifting impact of the project based on this range of factors could thus be approximately 3.46 to 4.99 *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 345 to 498 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	Marathon Project	Phillips 66 Project	Both Projects
Fuel Shift (millions of gallons per day) [a]			
RD for in-state use	1.623	1.860	3.482
PD equivalent exported	1.623	1.860	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	3.46	3.96	7.42
RD from crop biomass feedstock	4.99	5.72	10.7
PD (petroleum distillate)	8.00	9.17	17.2
Net emission shift impact [d]			
Annual minimum (Mt/year)	3.46	3.96	7.42
Annual maximum (Mt/year)	4.99	5.72	10.7
Ten-year minimum (Mt)	34.6	39.6	74.2
Ten-year maximum (Mt)	49.9	57.2	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.

[84] 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 from large industrial GHG emitters in general, and refineries in particular, caused substantially increased particulate matter emission burdens in low-income communities of color throughout the state.[85] Clark and colleagues found persistent disparately elevated exposures to refined fuels combustion emissions among people of color along major roadways in California and U.S.[86] 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.[87]

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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[85] 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 19.
[86] 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 20.
[87] 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 21.

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 does not include, and does not report substantively on results from, any of several standard process hazard analysis requirements applicable to petroleum crude refining. It does not include or report substantive results of any Process Hazard Analysis (PHA),[88] Management of Change analysis, Hierarchy of Hazard Controls Analysis, Inherent Safety Measure, or written recommendations to prioritize inherent safety measures and then include safeguards as added layers of protection[89] from any potential project process hazard. Instead the DEIR concludes that project refining hazard impacts will be less than significant[90] based on a series of unsupported and incomplete or inaccurate assertions.

3.1.1 <u>Incomplete and inaccurate evaluation of process material explosion and fire hazard</u>

The DEIR seeks to quantify combustible and flammable material hazards from whole feedstocks but does not evaluate explosion or fire hazards associated with conversion of feedstocks in the refinery. This incomplete evaluation contributes to the inaccurate DEIR impact conclusion. HEFA feeds are converted to hydrocarbon gases which may be indistinguishable, in terms of explosivity, combustibility or flammability, from petroleum products in process reactors operating at high temperatures and extreme pressures, and this occurs at greater hydrogen concentrations than those conditions in petroleum refining. §§ 1.2.1–1.2.3.

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[88] A PHA is a hazard evaluation to identify, evaluate, and control the hazards involved in a process.
[89] *See* California refinery process safety management regulation, CCR § 5189.
[90] DEIR pp. 3.9-17, 3.9-18.

3.1.2 Unsupported and inaccurate comparison of project refining to petroleum refining

The DEIR assumes project processing will be "similar" to historic crude processing at the refinery to conclude that reduced feedstock throughput volumes and fewer operating process units[91] will reduce project process hazards. Its conclusion incorrectly equates the hazards of different types of equipment and process reactions without factual support. Available data it ignores suggest the types of process units to be repurposed experience hazard incidents more often than many other types of petroleum refining units, and show that switching to HEFA feeds could further increase process hazards in the repurposed equipment, as discussed in § 3.2 below.

3.1.3 Unsupported and incomplete evaluation of applicable process hazard control mandates

The DEIR concludes "continued compliance" with multiple "federal, state and local regulations and proper operation and maintenance of equipment" will ensure that process hazard impacts "would be less than significant."[92] However, the DEIR does not specify which provisions of existing process safety regulations and requirements applicable to petroleum refining might no longer be applicable to the proposed project biomass refining. The DEIR thus omits discussion of whether the project will be exempt from requirements to fully analyze and prioritize inherent safety measures—the essential, and most effective type, of process hazard protection, which is designed to eliminate specified hazards.[93] These omissions render its conclusion unsupported.

3.1.4 Incomplete and inaccurate evaluation of existing and available hazard control measures

The DEIR provides an incomplete and inaccurate review of available process safety measures. It gives only cursory mention to safeguards[94] such as equipment maintenance, contingency plans, and a safety plan to be updated for the project.[95] Then, it does not disclose that safeguards are relatively ineffective safety measures, or that crude refining safety standards require analysis of specific hazards to prioritize inherent safety measures because of this problem with safeguards.[96] Omitting the requirement to prioritize inherent safety measures in combination with safeguards[97] further obscures the need for evaluation of *specific* process hazards, which the DEIR omits.

[91] DEIR p. 3.9-17; DEIR Appendix-HAZ pp. 23, 25.
[92] DEIR pp. 3.9-17, 3.9-18; DEIR Appendix-HAZ p. 27.
[93] California refinery process safety management regulation, CCR § 5189.
[94] Surprisingly, nowhere in its 456 pages does Volume I of the DEIR discuss flares, one of the most frequently needed emergency safeguards against escalating hazards in process units to be repurposed by the project.
[95] DEIR Appendix-HAZ pp. 25, 27; DEIR pp. 3.9-17, 3.9-18.
[96] California refinery process safety management regulation, CCR § 5189.
[97] *Id.*

3.1.5 Improper reliance on unspecified future process hazard mitigation measures

The DEIR conclusion that there would be no significant process hazard to mitigate[98] is based on unspecified future hazard mitigation. "The facility's plan would be updated to reflect the changes in operations associated with the proposed Project. ... Update of the facility's current Safety Plan (Injury and Illness Prevention Program [Marathon 2020]) to reflect changed conditions ... would assist in reducing hazards of explosive or otherwise hazardous materials."[99]

In fact, the less-than-significant hazard conclusion in the DEIR assumes future actions to address hazards of project changes in refining—actions to be specified in plans to address those project changes which, it says, have not yet been developed. However, inherently safer measures which may be feasible to introduce during project design, review, and construction may no longer be feasible after the project is approved or built.[100] The DEIR does not identify or evaluate this potential for deferring hazard mitigation analysis to foreclose mitigation.

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.[101]

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.[102]

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[98] DEIR pp. 3.9-18, 3.9-19,
[99] *Id.*
[100] CSB, 2013 (Att. 7).
[101] 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.
[102] Karras, 2021a (Att. 2).

Differences between the new biomass feedstock proposed and crude oil are more extreme than those among crudes which Chevron ignored the hazards of before its August 2012 fire 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.[103] Carbonic acid forms from that oxygen in HEFA processing.[104] Carbonic acid corrosion is a known hazard in HEFA processing.[105] 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.[106]

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.[107]

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.[108] [109] [110] When they consume more hydrogen, they generate more heat.[111] Then they get hotter, and crack more of their feed, consuming even more hydrogen,[112] [113] so “the hotter they get, the faster they get hot.”[114] And the reactions proceed at

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[103] *Id.*
[104] Chan, 2020. *Converting a Petroleum Diesel Refinery for Renewable Diesel;* White Paper / Renewable Diesel. Burns McDonnell. www.burnsmcd.com. Appended hereto as Attachment 22.
[105] *Id.*
[106] Karras, 2021a (Att. 2).
[107] *Id.*
[108] 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 23.
[109] 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 24.
[110] Chan, 2020 (Att. 22).
[111] van Dyk et al., 2019 (Att. 24).
[112] *Id.*
[113] Robinson and Dolbear, 2007 (Att. 23).
[114] *Id.*

extreme pressures of 600–2,800 pound-force per square inch,[115] 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,[116] 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.[117]

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.[118] And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.[119]

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.[120]

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*[121] 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.

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115 *Id.*
116 *Id.*
117 Karras, 2021a (Att 2).
118 Chan, 2020 (Att. 22).
119 Karras, 2021a (Att. 2).
120 *Id.*
121 Process Safety Integrity *Refining Incidents;* accessed Feb–Mar 2021; available for download at: https://processsafetyintegrity.com/incidents/industry/refining. Appended hereto as Attachment 25.

- 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 this Martinez refinery, then owned by Tosco.
- 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.

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.[122] [123] 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.[124]

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

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[122] Robinson and Dolbear, 2007 (Att. 23).
[123] Chan, 2020 (Att. 22).
[124] Karras, 2021a (Att. 2).

current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the Marathon Martinez and Phillips 66 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.[125]

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.[126] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[127] 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.[128]

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

Since switching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents, and flaring has proven unable to prevent every incident from escalating to catastrophic proportions, catastrophic consequences of HEFA process hazards are foreseeable.[129] The DEIR did not identify, evaluate, or mitigate these significant potential impacts of the project.

[125] *Id.*; and BAAQMD *Causal Analysis Reports for Significant Flaring;* Bay Area Air Quality Management District: San Francisco, CA. Reports submitted by Marathon and formers owners of the Marathon Martinez Refinery, and submitted by Phillips and former owners of the Phillips 66 San Francisco Refinery at Rodeo, pursuant to BAAQMD Regulation 12-12-406. Appended hereto as Attachment 26.
[126] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[127] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[128] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[129] Karras, 2021a (2021).

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 26 (*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."

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."[130] 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:

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.

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[130] CSB, 2013 (Att. 7).

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.

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.[131] The DEIR reports this,[132] and identifies a flare maintenance turnaround during 2018.[133] However, the DEIR does not discuss potential environmental impacts of project flaring anywhere in its 456 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.

[131] DEIR pp. 2-22, 3.3-1, Figure 2-9.
[132] DEIR pp. 2-22, 3.3-1, Figure 2-9.
[133] DEIR p. 3-5, Table 3-5.

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 data, 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 standard cubic feet (SCF) of vent gas each, and many flared more than ten million SCF.[134] 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.[135] By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.[136] [137] These same significance thresholds were used to require Marathon and Phillips 66 to report the flare incident data described in subsection 3.2.4 and in this subsection above.[138] [139]

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the Marathon Martinez and Phillips 66 Rodeo refineries *individually* exceeded a relevant significance threshold

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[134] Karras, 2021a (Att. 2).
[135] 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 27.
[136] 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 28.
[137] 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
[138] *Id.*
[139] BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).

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,[140] which is what implementing the project would do. Consequently, the proposed project can be expected to result in significant episodic air pollution impacts.

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

Further, the project would do more than repurpose the same process units that flare without removing the underlying causes for that flaring. The project would switch to new and very different feeds with new corrosion and mechanical integrity hazards, new chemical hydrogen 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.[141] 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.[142] Acute and chronic exposure impacts differ.

[140] *See* Section 3 herein; Karras, 2021a (Att. 2).
[141] DEIR pp. 3.3-14 to 3.3-16, 3.3-25 to 3.3-40, Appendix AQ_GHG. *See* also DEIR pp. 3-3 to 3-6.
[142] 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 29.

4.3.1 <u>The DEIR air quality analysis failed to consider the environmental setting of the project</u>

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 failed to properly consider these crucial features of the project environmental setting.

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.[143] 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."[144] 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."[145] 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

[143] DEIR p. 3.3-8; Table 3.3-2.
[144] Ezersky, 2006 (Att. 28).
[145] *Id.*

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 OBSCURES THE SIGNIFICANCE OF PROJECT IMPACTS BY ASSERTING AN INFLATED FUTURE BASELINE WITHOUT FACTUAL SUPPORT

The baseline condition for comparison with project impacts includes the existing petroleum storage and transfer operation at the project site. The DEIR, however, compares project impacts with those of a petroleum refinery with crude feed capacity more than three times the biomass feed capacity of the proposed project. It argues for this "future baseline" by stating such a crude refinery operated and was permitted to operate at the site historically, but provides no factual support for speculating that those historic conditions will become future conditions at the site. The DEIR does not disclose or evaluate evidence which strongly suggests that a future return to historic crude refining at the site is unlikely. As a result of these errors the DEIR inflates the project baseline and systematically understates the significance of project impacts.

5.1 The DEIR Does Not Describe Existing Baseline Conditions That Suggest its Conclusion Linking Project and Onsite Crude Refining Outcomes is Unfounded

5.1.1 <u>Petroleum storage and transfer rather than refining is the existing project site condition</u>

From before the project was proposed until now, the existing primary use of the proposed project site has been and is for petroleum storage and transfer operations.[146] The DEIR, however, concludes that the project baseline is petroleum crude refining at historic rates.[147] The project baseline asserted by and applied in the DEIR does not represent existing conditions.

5.1.2 <u>Petroleum crude refining at the site has been shuttered with no plans to restart</u>

Marathon shuttered crude refining operations at the refinery on 28 April 2020.[148] In July 2020, Marathon asserted that closure was permanent with no plans to restart the refinery.[149] The DEIR

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[146] *See* DEIR p. 2-22; Table 2-1 (existing petroleum storage for distribution to be maintained).
[147] DEIR pp. 3-3 through 3-7.
[148] April 28, 2020 Flare Event Causal Analysis for Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758, submitted to the Bay Area Air Quality Management District dated June 29, 2020. Accessed from www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports. *See* BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[149] BAAQMD, 2021. Workshop Report, Draft Amendments to Regulation 6, Rule 5: Particulate Emissions from Petroleum Refinery Fluidized Catalytic Cracking Units. January 2021. Bay Area Air Quality Management District: San Francisco, CA. *See* p. 14 FN; captions of tables 1, 2, 6, 8–10.

contradicts this public assertion by the project proponent without identifying, evaluating, or otherwise addressing the contradiction.

5.1.3 The project launched after crude refining ceased permanently at the site

Marathon was "evaluating the possibility" of this project in August 2020,[150] began "detailed engineering" for the project during October–December 2020,[151] and "approved these plans" on February 24, 2021.[152] All of that occurred after the April 2020 crude refining closure and July 2020 announcement that closure was permanent, but the DEIR does not disclose or address this evidence that decisions by the refiner regarding onsite crude refining predated and were not linked to decisions about the project. In addition, the DEIR does not discuss or explain the discrepancy between the Project Description, which does not propose restarting crude refining as an alternative to the project, and the opposite assumption in its baseline analysis.

5.2 The DEIR Does Not Disclose or Evaluate Available Evidence that Future Restart of Onsite Crude Refining is Unlikely due to Factors Independent from the Project

Converging lines of evidence which the DEIR does not disclose or evaluate strongly suggest that the shuttered crude refinery is unlikely to restart whether or not the project proceeds.

5.2.1 Available evidence indicates that the crude refinery closed during a refining assets consolidation that proceeded before, and independently from, plans for the project

Available evidence indicates that the refinery closed as part of a consolidation of refining assets. Refining assets follow the rule of returns to scale. Over time, smaller refineries expand or close.[153] Consolidation, in which fewer refineries build to greater capacity, has been the trend for decades across the U.S.[154] The increase in total capacity concentrated in fewer plants[155] further reveals returns to scale as a factor in this consolidation. Access to markets also is a factor. The domestic market for engine fuels refined here is primarily in California and limited

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[150] August 25, 2020 email from A. Petroske, Marathon, to L. Guerrero and N. Torres, Contra Costa County.

[151] US Securities and Exchange Commission Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2020, by Marathon Petroleum Corporation. Accessed from https://www.marathonpetroleum.com/Investors/ *See* p. 50.

[152] *Id.*

[153] Meyer, D.W., and Taylor, C.T. The Determinants of Plant Exit: The Evolution of the U.S. Refining Industry. Working Paper No 328, November 2015. Bureau of Economics, Federal Trade Commission: Washington, D.C. https://www.ftc.gov/system/files/documents/reports/determinants-plant-exit-evolution-u.s.refining-industry/wp328.pdf

[154] *Id.*

[155] *Id.*

almost entirely to the West Coast.[156] [157] Tesoro, Andeavor, and Marathon expanded refining capacity elsewhere in this market instead of at the Martinez Refinery—investment decisions that created the largest refinery on the West Coast in Los Angeles[158] and left Marathon with *extra* capacity in California, and across the West Coast, even after its Martinez crude refinery closed. See Table 9.

Table 9. Total Operable Atmospheric Crude Distillation Capacity of West Coast Refineries Owned by Marathon Petroleum Corp. / Andeavor / Tesoro Refining and Marketing, 2010–2021. [a]

Capacities in barrels per calendar day (b/cd) from January 1 of each year.

Year	Los Angeles, CA	Martinez, CA	Anacortes, WA	California Subtotal	CA & WA Subtotal
2010	96,860	166,000	120,000	262,860	382,860
2011	94,300	166,000	120,000	260,300	380,300
2012	103,800	166,000	120,000	269,800	389,800
2013	103,800	166,000	120,000	269,800	389,800
2014	355,500	166,000	120,000	521,500	641,500
2015	361,800	166,000	120,000	527,800	647,800
2016	355,170	166,000	120,000	521,170	641,170
2017	364,100	166,000	120,000	530,100	650,100
2018	341,300	166,000	120,000	507,300	627,300
2019	363,000	161,500	119,000	524,500	643,500
2020	363,000	161,000	119,000	524,000	643,000
2021	363,000	—	119,000	363,000	482,000
	Growth in capacity from 2010–2020 in barrels per day:			261,140	260,140
	Growth as a percentage of Martinez capacity on 1/1/20:			162 %	162 %
	Growth in capacity from 2010–2021 in barrels per day:			100,140	99,140

[a] Data from USEIA, 2021. *Capacity Data by Individual Refinery*. (Att. 16).

Since refineries wear out in the absence of sufficient reinvestment,[159] and run more efficiently when running closer to full capacity, those decisions to invest and expand elsewhere set the stage for refining asset consolidation. Its setting, landward of a shallow shipping channel that forces tankers to partially unload, wait for high tide, or both, before calling at Martinez[160] further set up

[156] USEIA, 2015 (Att. 11).
[157] The DEIR baseline analysis does not explicitly blame COVID-19 for the Marathon Martinez crude refinery closure, however, it bears note that the DEIR does not identify any other California refinery that closed during the pandemic, and it appears that this is the only California refinery to close coincident with the pandemic to date.
[158] Marathon Petroleum Corp., 2019 Annual Report, Part I, p. 9 (2019 Annual Report). https://www.annualreports.com/HostedData/AnnualReportArchive/m/NYSE_MPC_2019.pdf.
[159] Karras, 2020 (Att. 10).
[160] 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 EIS Appendix D. *See* p. ES-3, maps. Appended hereto as Attachment 30. *See* pp. ES-3, D-22, D-24, maps.

the refinery to close in that consolidation. Indeed, Marathon informed investors that it expected to complete the "consolidation" and expansion of its refining facilities in Los Angeles in the first quarter of 2020,[161] just before it finally closed the refinery in April. In fact, closing the refinery lets Marathon run its Los Angeles and Anacortes refineries closer to full. See § 5.2.2.

The sequence of events further links crude refining closure at Martinez to consolidation and not to the project. The refining assets consolidation began years ago, before Marathon owned those assets, and its Los Angeles refinery expansion component appeared to be complete before early 2020 (Table 9), when its CEO expected to complete the consolidation.[162] Marathon shut down crude refining at Martinez in April 2020 (§ 5.1.2). Then, and only after that shutdown, Marathon launched this project (§ 5.1.3). Timing links the shutdown to consolidation, not to the project.

5.2.2 Closing the crude refinery relieved a pre-existing condition of serious and growing petroleum refining structural overcapacity in California and on the West Coast

The DEIR baseline analysis does not consider available evidence that, instead of its unsupported choice between only the project and onsite crude refining, the true alternative to the project may be refinery decommissioning. Crude refineries in this fuels market have long been overbuilt and, for more than a decade as demand for petroleum fuels declined in their domestic markets, have exported large and growing volumes of their petroleum fuels production to more distant markets where their exports command lower prices.[163] But even with those exports, and even during the recent strong petroleum fuels demand surge in their domestic markets, California and West Coast refineries continued to run well below capacity. § 2.2. Idle California refining capacity during the recent demand surge exceeded the former capacity of the Martinez refinery and approached the Marathon Los Angeles refinery capacity (§ 2.2; Table 5, Table 9).

The growing structural overcapacity that idled up to 305,000 b/d of refining capacity during the recent fuels demand surge in California could have idled 466,000 b/d, had Marathon not closed its Martinez refinery (§ 2.2; Table 5, Table 9). Marathon had recently expanded its West Coast capacity so much that it was left with more refining capacity after closing Martinez than it had before its Los Angeles capacity expansion began. Table 9. The refiner then faced a choice

[161] 2019 Annual Report. See "From the Chairman and CEO" at p. 1.
[162] *Id.*
[163] See § 2.2 herein; see also Karras, 2020 (Att. 10).

between spending more on three refineries running closer to empty and spending less on two refineries running closer to full—with essentially equivalent domestic market share and declining demand. Two refineries closer to full could be more profitable. Marathon shuttered the Martinez crude refining operations. That relieved a growing overcapacity cost.

Moreover, if Marathon still found crude refining at Martinez profitable there was no reason for it to shut that off before project construction. Phillips 66, for example, is refining crude in Rodeo while it seeks approval for its Rodeo biofuel plans, and proposes to refine still more crude there while rebuilding for biofuel refining.[164] The DEIR does not explain its conclusion that crude refining will occur here without the project when it has not occurred here since April 2020.

5.2.3 <u>The crude refinery stayed closed when statewide fuels refining began to rebound in 2020</u>

Through the summer of 2020 statewide refinery engine fuels production began a partial rebound. From its deeply cut late-April 2020 low, combined refinery gasoline, distillate and jet fuel yield statewide rose 26% by the first week of June, 27% by the first week of July, 32% by the second week of August, then 36% and 39% by the first and last weeks of September, respectively.[165] Marathon did not restart crude refining in Martinez, instead announcing in July 2020 that it has no plans to restart the refinery. § 5.1.2.

5.2.4 <u>Marathon did not restart the crude refinery when petroleum fuels demand rebounded to approach and then reach pre-COVID levels from April through July of 2021</u>

By July 2021 a strong surge in petroleum fuels demand that started in April reached pre-COVID levels, accounting for seasonal and interannual variability, across California and the West Coast as a whole. § 2.2. Crude refining did not restart at the Martinez refinery during this strong surge in demand, and has not restarted to date. In fact, the actions taken by Marathon before and since the company shuttered the crude refinery and its assertion of no plans to restart the crude refinery are consistent with its closure in the refining assets consolidation and with effects of structural overcapacity discussed above. The DEIR does not consider this available evidence suggesting that the Marathon Martinez crude refinery will not restart.

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[164] County File No. CDLP20-02040.

[165] CEC *Fuel Watch* (Att. 13).

5.3 The DEIR Does Not Evaluate Technological, Energy Policy, or Climate Policy Factors That Further Suggest Re-establishment of Crude Refining Operations at the Project Site is Unlikely Whether or Not the Project Proceeds

5.3.1 Battery-electric vehicles growth would worsen petroleum refining overcapacity

A superior technology has emerged that is very likely to replace internal combustion engine (ICE) vehicles, reducing demand for combustion fuels, worsening refining overcapacity, and greatly increasing the implausibility of resuming historic Martinez crude refining operations. Going roughly three times as far per unit energy with fewer moving parts to wear and replace, battery-electric vehicle (BEV) technology has—or will soon have—lower total car ownership cost than ICE technology.[166] U.S. and foreign automakers report investments in production of lower sticker-price BEVs. The DEIR does not evaluate BEV effects on refinery restart.

Charging infrastructure buildout[167] and the balance of post-tax public subsidies to BEV *versus* ICE technology appear relevant to how quickly the postulated refinery restart could become clearly implausible, as discussed in § 5.3.3.

5.3.2 State energy and climate policies could worsen petroleum refining overcapacity

California climate and energy policies have converged on broad goals to replace ICE vehicles with zero-emission vehicles (ZEVs) while dramatically expanding solar, wind, and electrolytic hydrogen fuel infrastructure for those ZEVs—BEVs and fuel cell-electric vehicles.[168] Cuts in gasoline-powered transport of roughly 90% by 2045 are targeted along with near-100% renewable electricity as essential to climate stabilization by state-sponsored planning research toward these goals.[169] This would reduce refined fuels demand and hence the plausibility of refinery restart. How much, and how quickly, may depend in large part on local land use commitments to zero-emission infrastructure, however.[170] The DEIR baseline analysis does not consider effects of state ZEV plans or local siting actions on refinery restart.

5.3.3 Mutually reinforcing technology and policy factors suggest refinery restart is unlikely

The future remains uncertain—as the DEIR examples by assuming future uses of the project site could only be for the project or crude refining—and still, a general observation can be drawn

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[166] Karras, 2021a (Att. 2).
[167] *Id.*
[168] *Id.*
[169] *Id.*
[170] <u>*See*</u> Karras, 2020 (Att. 10).

from the information reported in subsections 5.3.1 and 5.3.2. Interactions, however imperfect, between the capability of BEV technology to replace petroleum, state capabilities to support its ZEVs goal, and local capabilities to site and host appropriate and desirable land uses would tend to accelerate replacement of ICE with BEV vehicles.

For example, the state might subsidize buildout of charging infrastructure, enabling more people to use BEVs, who may in turn support siting more charging infrastructure in their communities.

Relevant to the DEIR baseline analysis, these mutually reinforcing technology and policy factors will likely work together to reduce future petroleum fuels demand more quickly than either factor would reduce it alone, thereby decreasing the plausibility of future crude refining restart. The DEIR does not consider these relevant factors in its baseline analysis.

CONCLUSION: The DEIR baseline conclusion, that petroleum refining would restart onsite in the future if the proposed project does not proceed, fails to represent existing conditions and is speculative, unsupported by facts in the DEIR and rebutted by available evidence that the DEIR does not disclose or evaluate. The use of this inflated baseline in the DEIR was an error that obscured the significance of project impacts and resulted in a deficient impacts evaluation.

CONCLUSIONS

1. The DEIR provides an incomplete, inaccurate, and truncated or at best unstable 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 baseline conclusion, that petroleum refining would restart onsite in the future if the proposed project does not proceed, fails to represent existing conditions and is speculative, unsupported by facts in the DEIR and rebutted by available evidence that the DEIR does not disclose or evaluate. The use of this inflated baseline in the DEIR was an error that obscured the significance of project impacts and resulted in a deficient impacts evaluation.

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

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14. 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. https://ww2.arb.ca.gov/ghg-inventory-data

15. CDTFA, various years. *Fuel Taxes Statistics & Reports;* California Department of Tax and Fee Administration: Sacramento, CA. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm.

16. USEIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity

17. USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Inf. Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm 18. 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.

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28. Ezersky, 2006. *Staff Report: Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* 3 March 2006. Planning and

Research Division, Bay Area Air Quality Management District: San Francisco, CA. See *esp.* pp. 5–8, 13, 14.

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ATTACHMENT B

TECHNICAL SUPPLEMENT

Greg Karras

Senior Scientist, Community Energy reSource

FEIR figures 3-1 to 3-4 are <u>not</u> evidence for crude refining restart

Instead of responding to evidence that this crude refinery closed in a corporate consolidation of refining assets driven in large part by a growing gap between refining capacity and domestic demand,[1] the FEIR argues that California petroleum consumption trends *alone* provide evidence crude refining would restart here absent the project.[2] That is not true, because the refining fleet—including the part of it owned by Marathon—has been overbuilt. This overcapacity is measurable and demonstrable by comparing crude refining rates to crude refining capacity, as our DEIR comments showed.[3] Having ignored this fact in response to comment, the FEIR now presents "new" data which it says supports crude refining restart, but which do not.

A standard refining measurement, operable utilization rate (capacity utilization)[4] reveals refinery overcapacity. More precisely, it measures the otherwise operable crude capacity that lays idle after serving profitable demand. Measured as percentage of capacity in barrels per calendar day (b/cd), it accounts for downstream bottlenecks in the refinery, for scheduled and unscheduled down time, and for environmental constraints associated with refinery operations. Thus, for example, a capacity utilization of 90 percent means that ten percent of otherwise operable refining capacity is idled.

Charts 1A and 1B illustrate capacity utilization trends across refineries in California and the West Coast (PADD 5). Data shown are five and ten-year running averages. The long-term comparisons reveal structural overcapacity more reliably than short-term averages, which can mask the real trend in "noise" created by external factors such as unrelated economic cycles.

The ten-year mean comparisons reveal clear trends. West Coast capacity utilization fell from approximately 90 percent during the ten years ending in 2006 to below 86% during the ten years ending in 2013, and was below 86 percent for nearly all of the period from 2014 to the present (Chart 1A). California refining fleet capacity utilization was lower still. Fully 15 to 17 percent of operable capacity statewide sat idle on average during the 16 years ending over the period including 2014 through 2020 (*Id.*). Five-year mean utilization fell even more dramatically in the period from 2006–2017, partially rebounded more quickly as well, but never approached the historic peak refinery utilization for the five years ending in 2006 (Chart 1B).

Data shown in charts 1A and 1B were taken from the California Energy Commission Fuel Watch[5] and the US Energy Information Administration refinery capacity[6] and capacity

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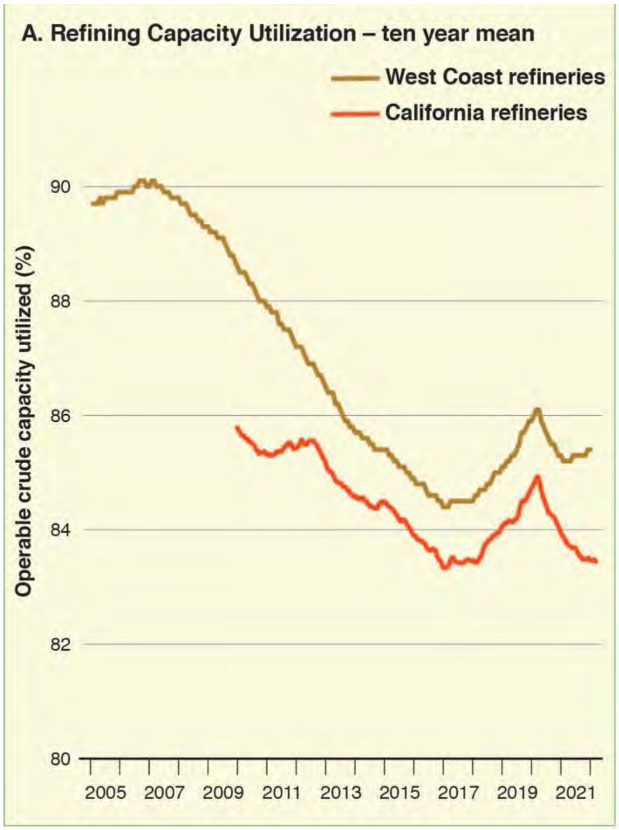
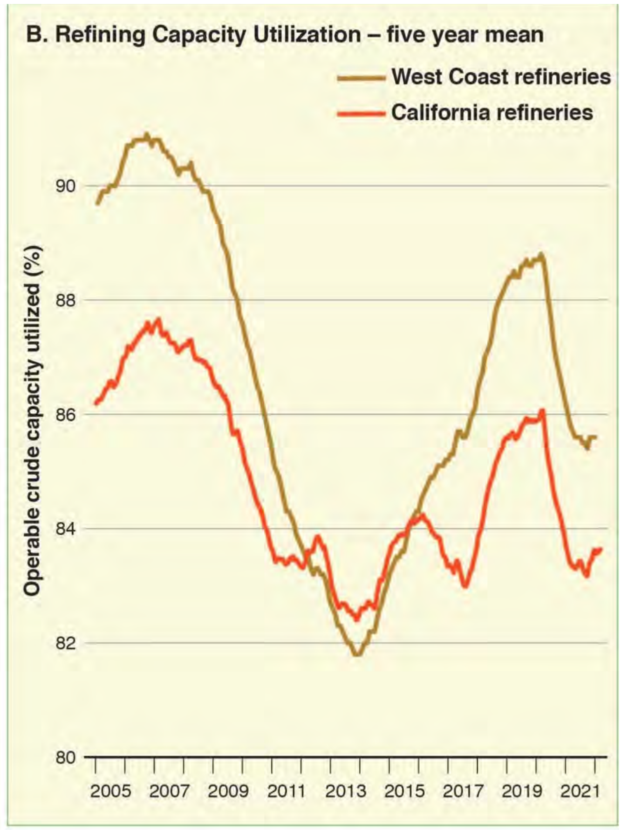
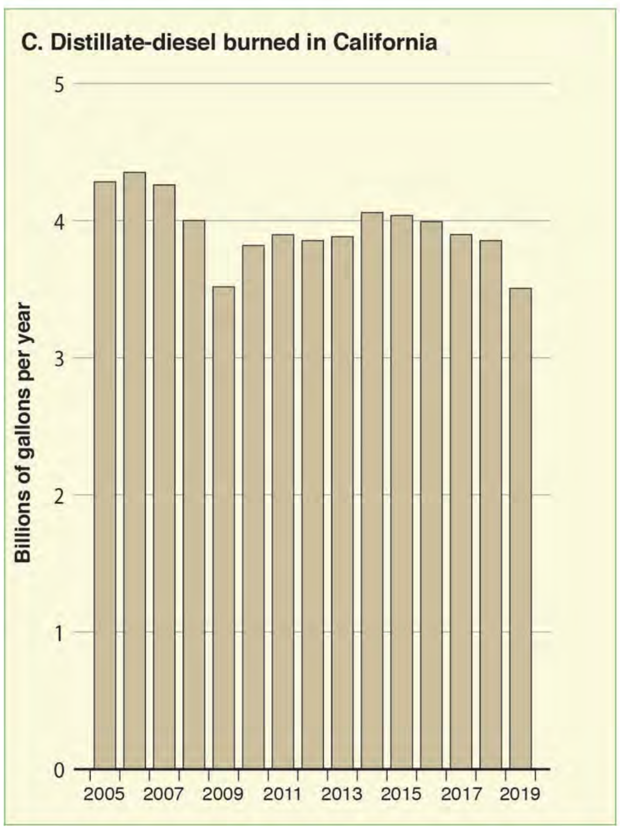
[1] <u>*See*</u> Attachment B, comment O12, Section III.
[2] Master Response 1 at 3-5 to 3-9.
[3] <u>*See*</u> Comment O12 Attachment C at 16 to 20, 36 to 40.
[4] Defined here as the US Energy Information Administration (USEIA) defines operable utilization rate, capacity utilization represents the utilization of atmospheric crude distillation units, and is calculated by dividing the gross input to these units by the operable calendar day refining capacity of the units.
[5] <u>*See*</u> Attachment 13 to Comment O12 Attachment C, and the Fuel Watch Data Update accompanying the technical supplement to the comments submitted by Natural Resources Defense Council to the Planning Commission dated March 22, 2022 (NRDC Comments).
[6] <u>*See*</u> Attachment 16 to Comment O12 Attachment C; <u>*see*</u> *also* U.S Energy Information Administration: Washington, D.C. *Refinery Capacity Data by individual refinery as of January 1, 2021;* www.eia.gov/petroleum/refinerycapacity

utilization[7] databases. Data shown in Chart 1C, discussed below, were taken from the California Air Resources Board fuel activity inventory.[8]

[7] *See* Attachment 16 to Comment O12 Attachment C, and the Capacity Utilization Data Update accompanying the NRDC Comments.
[8] *See* Attachment 14 to Comment O12 Attachment C.







Charts 1. California refineries over-built.
Fully 15 to 17 percent of statewide refining capacity that had not yet been decommissioned sat idle over the period from 2014 to 2019, the most recent six years before the COVID-19 pandemic.

A. Rolling ten-year mean utilization of operable crude refining capacity in California (red) and the U.S. West Coast (brown). California hosts most of West Coast refining capacity. Data are provided.[5–7]

B. Rolling five-year mean utilization of operable capacity for the same period, 2005–2021.[5-7]

C. Total petroleum distillate fuels including diesel burned in California annually from 2005 to 2019, the most recent year when the state reported complete data.[8] Chart does not include jet fuel or biofuels.

Declining West Coast petrofuels demand is one factor idling refining capacity. Continued consolidation of assets in fewer, larger plants is another. In Los Angeles, Marathon Corp. expanded what is now the largest West Coast refinery before closing its Martinez refinery. Now Marathon has 38 percent more statewide refining capacity in 2022 than it had in 2010, *despite* closing its Martinez refinery in 2020.[3]

Thus, the direct and objective indicator of refining overcapacity, operable capacity that sits idle, shows it is worsening (see Chart 1A) making any restart of crude refining less and less plausible.

Another observation illustrated by this chart, that the West Coast refining capacity utilization trend mirrors that in California but is not yet as low (*Id.*), further reveals the severity of the refining overcapacity problem in California.

Moreover, Chart 1A shows that instead of closing the gap between refining capacity utilization in California and that of the West Coast when Marathon shuttered the Martinez refinery in April 2020, the gap widened (*Id.*). This is consistent with and further strengthens the evidence its huge Los Angeles refining expansion, which worsened the statewide overcapacity problem Marathon shares, and leaves now with more California refining capacity—even after it shuttered crude refining at Martinez—than it had in 2010,[9] led Marathon to shutter its Martinez refinery.

As to the assertion that rising California petroleum fuels demand will result in restarting the crude refinery, the FEIR observes that in-state gasoline demand has declined since 2005,[10] and Chart 1C reveals that, when data from 2005 through 2008 the FEIR excluded from Figure 3-2 is considered, like gasoline, in-state distillate-diesel demand has declined since 2005.

The FEIR provides no relevant factual evidence for its assertion that the shuttered Martinez crude refining operations will restart due to future in-state demand for petroleum fuels.

Permit retention is <u>not</u> evidence for crude refining restart

The FEIR assert that retention of project site permits it lists in Table 3-1 is evidence the crude refinery would restart absent the project. It is not, because there are other reasons for Marathon to hold onto permits, which the FEIR does not disclose, evaluate or address in substantive terms.

In fact, there are several obvious reasons why Marathon would retain most, or all of the permits listed in Table 3-1 that are independent from any crude refining restart or plans for that restart. Its lease for the Avon and Amorco marine terminals would be needed for its currently existing petroleum storage and transfer equipment and operations at the site, and would be needed to implement its proposed project. BAAQMD permits in the record show these now-existing storage and transfer activities, marine terminals, and many existing on-site emission sources would require permits now, and would require permits for existing refining equipment to be repurposed for biofuel processing should the project proceed. Other onsite terminal and tank farm (SWRCB) stormwater discharge (RWQCB), hazardous waste (CDTE, CCHC), fire engine and nonvehicular source (CARB), and potable water (CCHC) activities that are ongoing now, will occur should the project proceed, or both, appear to require permits or fees independently from a restart of crude refining operations at the site. Simply assuming that the permits it lists can have no other purpose than crude refining, as asserted in the FEIR is not evidence.

The FEIR provides no relevant factual evidence for its assertion that the shuttered Martinez crude refining operations will restart.

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[9] *<u>See</u>* Comment O12 Attachment C at 16 to 20, 36 to 40.
[10] FEIR at 3-8.

Operating fewer other equipment components is not evidence the project will prevent or mitigate significant potential hydrogen-related process hazard or flaring impacts.

Master Response 5 includes a vague assertion that the project would prevent or reduce process hazards and flaring by using fewer equipment components outside the hydro-conversion units to be repurposed than did the historic refining operation. Perhaps the only specific example to explain this assertion that is given in the FEIR refers to fewer process furnaces which will not consume as much fuel.[1] In fact, 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.[2]

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 the FEIR referenced, other heaters and turbines. Further, the reason given for the reduced firing implicates project process units—hydro-conversion process units—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[3] would reveal substantial evidence for the potential significance of removing this de facto process hazard and flare minimization safeguard.

Moreover, Marathon has identified this hazard to air quality officials outside the present CEQA review—the need 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. It currently approved Flare Minimization Plan, which shows Marathon has identified this same flaring cause and discussed it more candidly outside the EIR, accompanies the technical supplement.[4]

Thus, in effect, the FEIR responds to comment in a manner that, the project proponent has previously stated to another agency, could increase the significance of project flaring impacts which the DEIR failed adequately to evaluate and mitigate. The EIR as proposed is deficient for this reason alone.

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[1] FEIR at 3-43.
[2] *See* Comment O12, Attachment C, part V for details of hydrogen-related and damage mechanism hazards.
[3] *See* Comment O12, Attachment C, part V and Attachment 26 thereto.
[4] Marathon FMP, 2020. Marathon Martinez Refinery, Tesoro Refining & Marketing Company, Flare Minimization Plan – 2020 Update. Public Version. 1 October 2020. Appended hereto as "Marathon FMP."

Martinez Refinery

Tesoro Refining & Marketing Company LLC

A subsidiary of Marathon Petroleum Corporation

Flare Minimization Plan - 2020 Update

PUBLIC VERSION

(Confidential Information Redacted)

PUBLIC VERSION
(Confidential Information Redacted)

Marathon's Tesoro

Martinez Refinery

Flare Minimization Plan

October 1, 2020

2020 Annual Flare Update

Certification Statement

Based on information and belief after reasonable inquiry, I certify that the flare minimization plan is accurate, true and complete.

June Christman, Environmental Manager

9/30/2020
Date

Contents

Attachments

1.0 Executive Summary

This report covers the time period of July 1, 2019 through June 30, 2020. Marathon's Tesoro Martinez Refinery's (Martinez) Flare Minimization Plan (FMP) continues to provide an effective method to minimize flaring. Attachment 17 includes plots displaying daily average flare gas flow rates and daily average mass emissions of sulfur dioxide (SO2), methane, and non-methane hydrocarbons (NMHC), all averaged over calendar years. These plots continue to show significant reductions in flaring magnitude since 2001/2002, indicating that the flare minimization plan is effective. Flare gas flow rate for this reporting period has been reduced by about 92% since 2001/2002. In addition, emissions of NMHC, SO_2, and methane also have been significantly reduced since 2001/2002. Of the seven reportable flaring events which took place during this reporting period, one was related to emergency situation (classified by the Regulation 12-12-201 definition), and the remaining six events were classified as non-emergency situations. The emergency situation resulted from the 4.5 magnitude earthquake centered in Pleasant Hill, California. The non-emergency events were all related to unit shutdowns or flare gas imbalances and were necessary to prevent an accident, hazard or release to atmosphere, and thus are covered within this FMP.

Due to reduced market conditions stemming from the 2020 COVID-19 pandemic, the Martinez refinery commenced the reduction of operations to an idle state on April 28, 2020. This reduction was safely completed in the following weeks, but the elimination of recycled flare gas consumers resulted in an increase of waste gas and recovered vapor being routed to the main refinery flare system. These increased vapor and waste gas flows in 2020 have resulted in lower reductions than have been accomplished in previous years, however waste gas routed to the main flare system is expected to decrease once the safe decontamination of idle process units and equipment is completed. This event is further discussed in section 3.4.1 "Maintenance Activities Including Startups and Shutdowns". In August 2020, the decision was made public that Marathon's management teams will idle the Martinez refinery indefinitely. This decision will necessitate changes to the flare minimization practices at this site, which will be reflected in the 2021 update to this plan.

2.0 FMP Background Information

2.1 Regulatory Background

Regulation 12, Rule 12, was adopted by the Bay Area Air Quality Management District (BAAQMD or the District) on July 20, 2005. The purpose of this regulation is to reduce emissions from flares at petroleum refineries. This flare minimization plan is provided pursuant to, and is consistent with, the requirements of that regulation. This plan outlines the efforts that have been and will be taken prior to situations that could be expected to lead to flaring, as well as actions that will be taken should unexpected flaring occur. Some of these actions are already in place and have led to significant reductions in flaring. The remaining actions will minimize flaring to the extent that refinery operations and practices will not be compromised with regard to safety. The key tools utilized to accomplish the minimization of flaring are careful planning to minimize or eliminate flaring, coupled with an evaluation of the cause of any flaring events that do still occur. Using this approach, an understanding of the events leading to a flaring event can then be incorporated into future planning and flare minimization efforts. This plan also examines the costs and benefits of potential equipment modifications to further increase flare gas recovery.

2.2 General Overview of 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.

Petroleum refineries are organized into groups of process units (units), with the general goal of maximizing the production of the mid-range (gasoline and diesel) materials. Each unit receives a set of feed streams, and in turn, 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 in a controlled manner, via relieving devices, to the flare header. These processes also produce and/or consume materials that are gases at atmospheric pressure. As a final step in processing, many units provide treatment to products and/or byproducts in order to conform to environmental specifications, such as reduced sulfur levels of various fuels.

Refineries are 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 as fuel for combustion equipment such as refinery heaters and boilers, Cogen, etc. Typical refinery fuel gas systems are configured so that the fuel gas header pressure is maintained by using imported natural gas to make up the net fuel demand. This provides a simple way to keep the system in balance so long as gas needs exceed the volume of gaseous products produced. Some additional operational flexibility is typically maintained by having the ability to burn other fuels such as propane or 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, steam turbines). The refinery typically stores propane and butane in pressure vessels, but can store propane and butane in railcars (if available) for additional storage capacity of these alternate fuels. A description of the wet gas, fuel gas, and flare gas recovery systems is provided in Attachment 1.

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. The primary function of the flare header is safety. It provides the process unit with a controlled outlet for any excess vapor flow, nearly all of which is flammable, making it an essential safety feature of every refinery. Each flare header also has connections for equipment depressurization and purging (as required by BAAQMD regulation) related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices to handle upsets, malfunctions, and emergency releases.

Typical flare header design incorporates a knockout drum for separation of entrained liquid at the unit boundary. This minimizes the possibility of liquid being carried forward to the flare or flare gas compressor. Liquid will result in mechanical damage to most types of compressors and cannot be safely and completely burned in a flare.

The vapor stream from the unit knockout drum is then routed to the central refinery flare gas recovery system. A typical central 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 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 via combustion.

A flare seal drum is typically located in the line to the flare to serve several functions. A level of liquid, generally 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. Some flare systems combine multiple flares with a range of water seal depths, effectively "staging" operation of the various flares.

Gases exit the flare via a flare tip which is designed to promote proper combustion over a range of gas flow rates. Steam or air is often 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. First, 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 facility typically uses natural gas as the purge gas, but in some cases nitrogen is also used as purge gas to the flare. The pilot and purge gas flow rates for the main flare system and the ammonia plant flare are determined using an orifice calculation based on the size of the orifice located in each line, and the pressure of the line upstream of the orifice. The pilot and purge gas flows for 50 Unit flare are measured using flow meters.

To help ensure that refinery flares always operate with high combustion efficiency, a new EPA standard requires the Martinez Refinery to maintain the net heating value of flare combustion zone gas (NHVcz) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes.

Although this numerical limit is new, Martinez Refinery has historically maintained good combustion and prevented flare flame-outs by adjusting steam rates at the flare tip and adding natural gas to the flare gas at various locations in the header system when needed. For example, during turnarounds natural gas may be added to flare gas header system to ensure good combustion of flare gases during periods of high nitrogen and/or steam purges of units to the flare header. The vessel purges are used to clear hydrocarbon from vessels prior to opening to atmosphere, and the flare header system is equipped with manual valves at numerous locations that can be adjusted to increase supplemental natural gas.

In the past, Operations would communicate with the Flare operator to adjust natural gas addition. The automation of natural gas addition decreases response time and assures high combustion efficiency. This automation was completed for all refinery flares in compliance with the aforementioned Consent Decree and Refinery Sector Rule (RSR)

The sources of normal, or base level, flow to a refinery flare gas collection system are varied, but in general result from many small sources such as instrument purges, pressure control for refinery equipment items (e.g. overhead systems for distillation columns), or leaking relief valves. Added to this low level 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 can result from various other process functions, often related to operation of batch or semi-batch equipment (e.g. drum depressurization at a delayed coking unit). An example of a "batch" operation would be occasional (e.g. once/shift) venting of compressor snubbers. This is done to remove any liquid that may accumulate in the snubbers. The snubbers are drained to the flare knockout pot until any liquid is withdrawn, and a small amount of gas goes into the knockout pot, which then goes to the flare system. This small amount of gas goes to the flare system and is normally recovered via the flare gas recovery system (to fuel gas).

Similarly, maintenance conducted on equipment in LPG service would result in a batch operation to flare. The LPG is pumped from the equipment to the extent possible. To finish preparation of the equipment for opening, the last remaining LPG would be vented to the flare. Another example would be at the Hydrogen Plant, where copper impregnated activated carbon drums are used to remove trace sulfur compounds from the treated feed gas prior to going to the Steam Methane Reformer furnace. Each of these carbon drums is regenerated by using a back-flow configuration of 600 psi steam to remove the trace sulfur compounds from the carbon bed, with the resulting stream venting to the flare header. This operation is typically performed once per week.

Scheduled maintenance activities can result in higher than normal flow of material to the flare. During equipment maintenance, the equipment and associated piping must be cleared of hydrocarbon 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.

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 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 flow rate. This FMP outlines the approach that Martinez has developed to manage and minimize flaring events, without compromising the critical safety function of the flare system.

3.0 Flare Minimization Plan

3.1 Technical Data – Description of Martinez Flaring Systems

The following sections describe the sizing and operating parameters for the components of the Martinez flaring system.

3.1.1 Flare System & Control Descriptions

Main Flare System

Flare Headers

In the main refinery, there are currently three flare headers (with diameters of 42" and two of 48"), available for collection of various vent gas sources. These four flare headers are cross connected at various points, acting in practice as one interconnected flare header system. The flare headers route vent gases from process units to the flare area, where recycle compressors reprocess as much waste gas as possible. Due to a portion of one of the flare headers nearing end of life, a new flare header was installed to replace it.

Flare Area

The vent gas flows through the flare headers to a collection of knockout pots and water seal pots in the flare area. Knockout pots are vessels that remove any entrained or condensed liquid. The gas then goes to a water seal pot. The water seal pot is a vessel that prevents the vent gas from entering the flares until the pressure in the flare headers exceeds the water level in the seal pots.

Flares

The main flare system is comprised of six flares. These are the North Steam Flare, South Steam Flare, West Air Flare, East Air Flare, Coker Flare, and the Emergency Flare.

The flare source numbers, capacities (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
East Air Flare	S-854	45,600	1983
North Steam Flare	S-944	64,800	1955
South Steam Flare	S-945	64,800	1955
Emergency Flare	S-992	316,800	1983
West Air Flare	S-1012	66,120	1976

Coker Flare	S-1517	588,300	2007

Additional physical parameters for each flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
East Air Flare	75	24	3	0
North Steam Flare	28	24	3	8
South Steam Flare	28	24	3	8
Emergency Flare	75	48	4	0
West Air Flare	81	24	3	0
Coker Flare	200	42	3	64

The steam flares (North and South) use steam to aspirate air and improve smokeless operation. Similarly, the air flares (East and West) use air to improve smokeless operation. The Emergency Flare is designed to only operate during very high vent gas flows, such as during a total power failure. Therefore, it is not designed for smokeless operation, since there would not normally be power (for air assist) or steam available during such situations. The flares are "staged," that is, they are designed so that vent gas is sent to the flares progressively as the amount of gas increases. This is accomplished by setting the water levels in the seal pots at different levels. The typical order that vent gas is sent to the flares is: the steam flares, the Coker Flare, the East Air Flare, the West Air Flare, and the Emergency Flare. The order of the flares may change based on operational considerations and maintenance schedules for the flares. Then the flare order will change as needed. However, in any scenario, the emergency flare is always set to be last. The order is set through the use of water seal pots with varying levels of water in each seal pot that sets the flare order. The typical water seal heights are as follows:

- Steam Flares: 24"
- Coker Flare: 30"
- East Air Flare: 32"
- West Air Flare: 35"
- Emergency: 174"

By adjusting these water levels, the vent gas automatically goes to one or more flares. As the flow to the flare headers increases, the flare header pressure increases and exceeds the water level pressure, blowing through the water seal and going to the flare. As the flare header pressure decreases, the water seal is reestablished, and flow to the flare(s) stops. A small amount of natural gas is added to the flare line, after the water seal pot, to maintain a positive pressure to ensure that air does not enter the flare lines. A small amount of natural gas is also used for flare pilots to ensure proper combustion should a flaring event occur. There is no normal daily flow to the flare (i.e. the flare gas recycle compressors typically recover all of the gas being sent to the flare area). The 2005 average flow to the refinery main flare system was 0.8 MMSCFD. The purge gas sent to the flares in the refinery main flare system is natural gas and the 2005 average flow of purge gas to those flares was 0.13 MMSCFD.

Potential for Temporary Thermal Oxidizers and Portable Flares

To add flexibility during maintenance periods, the Martinez Refinery will utilize portable thermal oxidizers, portable flares or temporary H2S removal equipment. The use of such equipment would be during flare turnarounds, 5 Gas Plant turnarounds or other unforeseen mode of operation. The refinery normally schedules flare outages to coincide with process unit shutdowns.

Temporary H2S removal equipment for the 5 Gas Plant turnaround includes knockout pots, vent gas compression, caustic scrubbers, piping, and associated instrumentation. Please see permit condition for additional information.

Flare Gas Recovery System

At the flare area, incorporated into the flare system, is a flare gas recovery system. The system is comprised of a recycle compressor and a spare compressor (CP-539 and CP-540 rotate between being in operation and on cold standby as a spare) that draws flare gas from the flare headers and compresses the flare gas, sending it to the No. 5 Gas Plant (GP). At the No. 5 GP, the gas is further compressed and sent to an amine treating system for removal of sulfur compounds and is then sent to the fuel gas system. See Attachment 1 for additional details regarding the flare gas recovery, fuel gas, and wet gas systems.

Under normal refinery operating conditions, the flare gas recovery system recovers all of the vent gas. The flare gas recycle compressors have a nameplate capacity of 4.0 MMSCFD each and the maximum observed capacity is about 5.0 MMSCFD. The maximum design temperature for these compressors is 160° F on the compressor discharge. The compressor gas design molecular weight (MW) was based on three cases: a low MW case of 5.8, a typical MW case of 17.9, and a high MW case of 25.9. No maximum molecular weight was specified in the design.

The spare flare gas recovery compressor is in cold standby to reduce the risk of losing both compressors due to an adverse event. For example, if a slug of liquid entered the flare gas recovery compressor system and the existing systems failed to shut down the compressor, the compressor could be seriously damaged. If the spare compressor was set to automatically start, the spare compressor could also be seriously damaged which would result in all recovery compressor capability being lost for weeks or longer. However, by keeping the spare compressor in cold standby, if one compressor shuts down, procedures require that the operator determine the cause of the compressor shutdown and resolve that problem before attempting to start the spare recovery compressor. It typically takes about 15 minutes to start the spare compressor and another 10 minutes to bring the compressor to full rate. This reduces the risk that one event would take out both recovery compressors. Clearly, losing the recovery capacity for a few minutes is preferable to the risk of losing the recovery capacity for weeks or longer.

Recently, a number of regulatory considerations have directed Martinez to work toward operation of the second flare gas recovery compressor when the capacity of the first compressor has the potential to be exceeded. As a preventative measure, the refinery now starts up the second compressor in order to recover more gases. Operating the second compressor as well as controlling the depressuring sequence during shutdowns, has dropped the amount of flaring significantly.

However, as noted above, the risk of losing both flare gas recovery compressors increases. In addition to the situation described above, if the oxygen content of the flare gas exceeds 3%, both recovery compressors would be shut down, regardless of the operating mode, to ensure an explosive mixture does not occur in the compressors. Various other conditions can also result in the shutdown of both recovery compressors. Situations that would lead to the flare gas recycle compressor tripping off-line include but are not limited to:

- A low level in the flare gas compressor discharge knockout pot as indicated by a switch on the pot (LSLL-1124 and 1136) or by the transmitter on the pot (L-1125 and 1137) will trip the compressor. If the liquid level is too low, seal water circulation could be lost which would lead to damaging the compressor, the seal water pumps, or the seal water cooler.

- A high level in the flare gas compressor discharge knockout pot as indicated by the transmitter on the pot will trip the compressor (L-1125 and 1137). If the liquid level is too high, liquid could back into the compressor suction which would lead to a failure of the compressor.

- A low pressure on the suction line to the compressors will cause the compressor to trip. If a vacuum is pulled on the flare line, air could be drawn into the flare header causing the potential for an explosive mixture in process equipment. (PT-1120, PT-1130 and 1131)

- A low flow of seal water back to the compressor will trip the compressor. If the liquid level is too low, seal water circulation could be lost which would lead to damaging the compressor, the seal water pumps, or the seal water cooler. (F-1121 and 1133)

- A high level on the compressor suction pot (V-107) will shut down the compressor. Liquid carry over into the compressor would result in damage to the compressor. (L-1160)

- A high concentration of oxygen in the flare gas stream will cause the compressors to shut down. High oxygen levels in the flare gas could result in an explosive mixture and increased fouling in process equipment. (19-ASHH1161, 1162, 1163)

- A high compressor discharge pressure will cause the compressor to trip. This is to prevent damage to the compressor and associated equipment.

- A high pressure on the extraneous knockout pot at No. 5 GP will cause the compressor to trip. This is to prevent a recycle loop from occurring since the main accumulator at No. 5 GP will relieve to the flare system at 10 psig. (3-PSHH-4677/4675 1 of two voting)

- High bearing temperatures on the compressor (T-1145, 1146, 1147, and 1152) or on the compressor motor (T-1171, 1172, 1173, and 1174) will cause the compressor to trip. Continued operation during imminent bearing failures could result in catastrophic failure of the compressor.

- An electrical failure on the compressor motor/starter circuitry will cause the compressor to trip. Such an electrical problem could cause further damage to the motor or a result in a fire.

- If any one of the stop buttons are pushed, the compressors will trip. There is one located in the Thermal Area control room, one located at No. 5 GP, and one located at the local panel for the compressor.

There is no formal written procedure describing when it is permissible to re-start a flare gas recycle compressor, however, in most cases, the operator would restart the compressor or start up the other flare gas recycle compressor after the reason for the compressor trip was understood and corrected. The reason for the compressor trip must be identified and corrected prior to restarting either compressor to ensure that any potential safety or equipment hazards are properly addressed. Should the determination be made that the cause of the compressor trip was a mechanical breakdown of that specific compressor (and no other safety or equipment hazard existed), the other flare recycle compressor would be started. When neither of the flare gas recycle compressors are operating, the gases in the flare system will go to the flares.

The manufacturer's recommended frequency and schedule for the flare gas recycle compressor repair and maintenance is provided in Attachment 2. However, the maintenance recommendations contained in the Original Equipment Manufacturer (OEM) manual for the flare gas compressors are from a generic manual that the OEM supplies with all their products and so many of these recommendations are not completely consistent with the requirements of these specific compressors. The practices followed at Martinez are based on Industry Best Practices and are focused on improved equipment reliability. For example, Section 4-2 paragraph a., describes lubricated couplings which are not present on the flare gas recycle compressors at Martinez. The Martinez compressors utilize a disc-pack dry coupling. Additionally, Section 4-2, paragraph b & c, Section 4-3, and Section 4-4 describe frequency and procedure by which to lubricate various bearings and couplings. For the Martinez compressors, all bearings are fitted with automatic grease lubrication devices which inject a measured amount of grease at specific time intervals. This provides the best lubrication for the bearings. As a third example, Section 4-5 describes preventative maintenance procedures for stuff box packing within the compressor. The flare gas recycle compressors at Martinez do not have packing. Mechanical seals are required due to the potentially sour (sulfur containing) hydrocarbon gases contained in the process.

As part of the Predictive Maintenance program, Martinez monitors the vibration levels on these compressors monthly when they are in operation. In addition, the lubricators are checked monthly, as part of the vibration rounds, and semi-annually as part of the lubrication rounds. Martinez believes this maintenance regime is better suited to the flare gas recycle compressors.

The location of monitors that could trip off the flare gas recycle compressors are identified on the flare system process flow diagram (PFD). They are noted as a "T" near a circled item. The abbreviations used in circled items on the PFD are:

P	Pressure
T	Temperature
F	Flow
L	Level
A	Analyzer (typically oxygen)
RO	Restriction Orifice

The current trip settings are also included on the PFD. For example, the compressor knockout pot trip temperature is 160° F, the compressor motor bearings temperature trip is 180° F, and the compressor case temperature trip is 220° F. (The recovered flare gas temperature typically ranges between 80 and 120° F, and based on current knowledge, there has not been a flare event associated with the loss of the flare gas recovery compressors due to a high temperature trip of those compressors.

The only flare gas compressor trips that are not included on the PFD are:

1) the stop switches for the compressors, as noted above,
2) the high pressure on the extraneous knockout pot at No. 5 GP (which trips at 7 psig) and,
3) the electrical failure monitor on the compressor motor/starter circuitry.

These have not been included on the PFD because the equipment is not located on this PFD (i.e. the No. 5 GP and compressor motors) and would unnecessarily clutter the PFD.

The flare gas recovery compressors do not have a nitrogen content trip and the flare gas recovery compressors can handle essentially any amount of nitrogen in the gas. However, the amount of nitrogen that can be handled in the fuel gas system (which is the ultimate disposition of this gas) is limited. There is no defined nitrogen content specification for the fuel gas. The compressors are shut down for high nitrogen concentration if they are adversely affecting the heat energy value of the fuel gas or the operation of the No. 5 GP wet gas compressors.

ARU Flare

The Ammonia Recovery Unit (ARU) Flare is connected primarily to the ARU but also to the SCOT and DEA units. The majority of the flaring situations result from ARU operations. The ARU Flare is equipped with a MW analyzer which is used to provide the operators with an indication of the flare gas composition. The flare gas composition, depending on the value, can assist Operations in predicting whether a potential flaring event is likely. Corrective action can be taken to reduce and/or avoid the resulting flare events.

The ARU Flare is equipped with a relief scrubber upstream of the ARU Flare stack. The flare stack is also equipped with a knockout pot and water seal to remove entrained liquids, provide some additional scrubbing capacity and prevent backflow from the flare into the flare header.

The flare source number, capacity (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
ARU Flare	S-1013	6,408	1983

Additional physical parameters for the flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
ARU Flare	160	84 (bottom) 45 (mid)	3	0

<u>ARU Flare Relief Scrubber</u>

Gases from the relief header are fed to the scrubber where they are contacted with a continuously circulating stream of ammonia solution. This solution absorbs hydrogen sulfide (H_2S) and ammonia with the resulting overhead vapor flowing to the flare. Circulation of the ammonia solution is maintained by a scrubber pump on a continual basis. Should a large relief load be present, a second larger circulation pump is started which increases scrubbing capacity by 2.7 times. The rich circulating solution is purged from the scrubber and sent to the feed mixing drum for reprocessing through the ARU. The scrubber itself is designed with two compartments. The first is used during normal operating conditions whereas the second is used during upset conditions when extra H_2S and ammonia absorbing capacity is required.

<u>ARU Flare Description</u>

The flare system is comprised of the knockout drum, the water seal, and flare stack. The overhead vapors from the relief scrubber are fed to the knockout drum. This drum removes any entrained liquids and sends them to the feed mixing drum for reprocessing. The vapors from the knockout drum then feed the flare seal pot which contains a water seal to prevent backflow from the flare into the scrubbing section. The liquid in the water seal is flushed on an as needed basis and make up water is provided by cold condensate from the ARU. The vapor leaving the seal pot then passes through a molecular seal which effectively prevents any air from entering the flare stack below the seal for extended periods of time. The seal is flushed with hot condensate to clean the seal pockets.

The flare tip employs natural gas fired continuously operated pilots. Pilots can be relit remotely in the control room or at a local panel if low temperature is detected. A backup system can also be used. The manually operated flare front generator uses instrument air mixed with natural gas that flows to the pilots to re-ignite them.

50 Unit Flare

The 50 Unit Flare system is comprised of a new collection header, flare gas recovery system knockout drum, a new liquid ring flare gas recovery compressor, and a flare. In addition, the existing 50 Unit wet gas compressors are also connected into the flare gas recovery system for periods of larger flow and as a backup for the new flare gas recovery compressor. The recovered gas is routed to the refinery fuel gas system at the No. 5 GP. Any recovered liquid in the knockout drum is cooled and pumped to the refinery recovered oil system.

The flare source number, capacity (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
50 Unit Flare	S-1524	672,000	2010

Additional physical parameters for the flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
50 Unit Flare	310	30	3	42

The steam flare uses steam to aspirate air and improves smokeless operation. The typical water seal height is 61".

3.1.2 Process Flow Diagrams

A PFD of the Main Flare System and associated vessel diagrams are provided in Attachment 3.

The PFDs of the 50 Unit Flare system and associated seal pot diagram are provided in Attachment 3A.

The PFDs of the ARU Flare system and associated seal pot diagram are provided in Attachment 4.

3.1.3 Description of Monitoring and Control Equipment

A description of the monitoring for the Main Flare System, the 50 Unit Flare System and the ARU Flare is provided below. The control for these flares is included in the flare system information in section 3.1.1 above.

Main Flare System Monitoring

<u>Flare Flow Monitoring</u>

The 42", 48", and 48" flare header flows are monitored by an ultrasonic flow meter located in each of the flare headers. Ultrasonic flow monitors are also installed in the outlet of the flare gas recovery compressors, the line to the Coker Flare, and on the flare line to the steam flares. This data is provided in monthly reports to the District.

Currently, the amount of vent gas being flared is determined by adding all the flare header flows (i.e. the 42" and two 48" headers) and subtracting the recovered vent gas flows from the flare gas recycle compressors (also known as the flare gas recovery compressors). During low flows of vent gas to the flares, the Steam Flare flow meter is used, since the Steam Flares are the first flares to see flare gas. Martinez believes that this provides the best accuracy at the lower flare flow levels.

During these low flare flow situations (where the gas is only being sent to the steam flares), Martinez uses the steam flare flow meter to determine the amount of gas being flared. The output from this meter is compared to seal pot monitoring (i.e. seal pot water level vs. flare header pressure) to determine the flow. When the seal pot water level (expressed in inches of water column) exceeds the flare gas pressure at the seal pot (also expressed in inches of water column), this indicates that there is insufficient pressure in the flare header to go through the water seal, and there is no flow to the flare. In this case, there is zero flow for the flare.

By January 2019, to comply with the Consent Decree and Refinery Sector Rule, individual flare gas flow meters were installed after the seal drums at the East Air Flare, West Air Flare, and Emergency Flare. The East Air, West Air and Emergency Flare flows are monitored by Optical Scientific Inc. flow meters.

To address flows to the flare header system, Martinez employs various monitors to determine the source of flare gas to the system. Several flow meters are used to identify the process area or unit that is generating flare gas to assist in determining and reducing flow from that source. In addition, other operating parameters are monitored (e.g. pressure, valve position, etc.) to identify the source of flare gas. By routinely monitoring these parameters, proactive actions can be taken to identify the cause of the additional vent gas and, to the extent possible, take appropriate action. This has proven to be an effective method to minimize flare gas flows.

Flare Gas Composition Monitoring

As part of Martinez's plan to comply with NSPS Ja requirements, the flare gas composition monitoring scheme for the refinery was revised. Each flare in the main flare system and 50 Unit flare has an H_2S analyzer to monitor the concentration in the vent gas. The total sulfur content of the flare gas is analyzed by a continuous total sulfur monitor in the north and south steam flare line, since these are the flares that are normally first in the refinery staged flare system. When the Coker Flare is staged first, the Coker Flare H_2S analyzer is used.

For the Consent Decree, Martinez purchased gas chromatographs (GC) to measure the hydrocarbon content of the vent gas. Martinez certified these analyzers in 2017. We perform manual sampling when the GC's are not functioning. The hydrocarbon data is provided in monthly reports to the District.

Video Monitoring

In addition, cameras are used to obtain a visual record of each of the flares once per minute. These are archived as digital picture files (jpg format) and provided to the

District monthly on DVDs. Martinez has increased the number of flare pictures to meet the Consent Decree requirements of four pictures per minute.

Flare Seal Pot Level Monitoring
The water level in each of the flare seal pots is continuously monitored, along with the flare header pressure, near each seal pot. This data can be used to determine whether the water seals are intact as a way of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot lights remain lit. In addition, the amount of pilot gas and purge gas is monitored and reported to the District in the flare monthly reports.

ARU Flare System Monitoring

Flare Flow Monitoring
The ARU Flare flow is monitored by a continuous ultrasonic flow meter. This data is provided in monthly reports to the District.

Flare Gas Composition Monitoring
Due to the potentially high ammonia and H_2S content of the flare gas, representative, worst case compositions are used to determine emissions, pursuant to Regulation 12-11-502.3.1a.

Video Monitoring
A camera records a visual record of the ARU Flare once per minute. These are archived as digital picture files (jpg format) and provided to the District monthly on DVDs.

Flare Seal Pot Level Monitoring
The water level in the ARU Flare seal pot is continuously monitored, along with the flare pressure. This data can be used to determine whether the water seal is intact as a method of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot flames remain lit. In addition, the amount of pilot gas and purge gas is monitored and reported to the District in the flare monthly reports.

50 Unit Flare System Monitoring

Flare Flow Monitoring
The 50 Unit Flare flow is monitored by a continuous ultrasonic flow meter. This data is provided in monthly reports to the District.

Flare Gas Composition Monitoring
The sulfur content of the 50 Unit Flare header is monitored by a continuous monitor for H_2S. The hydrocarbon content of the flare header is taken manually during a flare event

and analyzed in Martinez's lab using a gas chromatograph to determine the hydrocarbon composition of the flare gas. This data is provided in monthly reports to the District.

Video Monitoring
A camera records a visual record of the 50 Unit Flare once per minute. These are archived as digital picture files (jpg format) and provided to the District monthly on DVDs.

Flare Seal Pot Level Monitoring
The water level in the 50 Unit Flare seal pot is continuously monitored, along with the flare pressure. This data can be used to determine whether the water seal is intact as a method of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot flames remain lit. In addition, the amount of pilot gas and purge gas are monitored and reported to the District in the flare monthly reports.

The locations of flow meters, temperature and pressure indicators are shown on the PFDs included in Section 3.1.2 above. The locations of sample points and continuous emission monitoring (CEM) equipment are also shown on the PFDs included in Section 3.1.2.

3.2 Reductions Previously Realized

Over the last decade, Martinez has significantly reduced flaring. This has been accomplished predominantly by starting up the second flare gas recovery compressor on the main refinery flare gas system, and through improved awareness and management of the flare system to minimize flaring. From July 2002 to present, non-methane hydrocarbon flaring emissions have been reduced from about 2 tons per day to about 0.075 tons per day on average (based on 2020 data). This represents a reduction of about than 95%. In 2016 Martinez further increased its efforts in decreasing flaring. During planned events, Operations and Planning have staggered shutdowns to stay within the capacity of the two compressors. During unplanned shutdowns, Operations has increased their efforts to startup the second compressor and make adjustments to decrease streams to the flare. These efforts have greatly reduced the number of flaring events in 2016 through 2020.

Martinez has reduced flare flows due the following:

- Planned use of the Flare header will be coordinated to prevent exceeding the capacities of the flare gas recovery compressors to the maximum degree practicable.
- All discretionary venting to the flare header due to planned maintenance will be coordinated with the Shift Superintendent. Operations staff filling this role manage such venting to stay within the Compressor capacity to the extent feasible.

- Planned venting activities which are anticipated to exceed the capabilities of the primary compressor will include proactively activating the second Compressor to prevent flaring.
- Base load to the flare gas recovery compressors are monitored. If there is an increase in the amount of waste gas recovered on a daily basis, the refinery has a procedure to find the source and eliminate the flow. This proactive monitoring allows for additional recovery capacity to offset flaring during actual flare events due to emergencies or unforeseen circumstances.

Other actions that have been taken to reduce flaring include improved planning efforts related to maintenance turnarounds and operational changes to keep the fuel system in balance. Prior to maintenance turnarounds, Martinez has evaluated the potential flaring that could occur as a result of the turnaround and developed plans to try to eliminate or reduce flaring (see Section 3.3, Description of Planned Prevention Measures for more information on this process). Such plans consider whether vent gases generated during shutdown and maintenance can be routed to other closed systems first to minimize material sent to the flare system, and for those vent gases that must still be sent to the flare, whether venting to the flare more slowly would help to stay within the flare recovery system capacity.

The plans also consider the timing of the various unit shutdowns and purging opportunities to keep the rate to the flare gas system within the recovery capability. For example, during the last planned major maintenance activity, units were prioritized relative to when they could depressure to the flare system. The flare gas recovery compressor flow was monitored to stay within the system capacity, and additional vessel purging and depressuring was conducted as system capacity was available. It should be noted, however, that situations can occur when the volume of nitrogen required to properly clear the vessel (and catalyst) of hydrocarbon material for safe entry is such that it can exceed the flare recovery system capacity. In addition, such plans have considered the use of chemicals to improve initial hydrocarbon removal to reduce the time needed for steam out or purging to flare.

In addition, various actions have been taken as a result of causal analyses performed for flaring events. These actions are included in Attachment 5.

Operations also manages the fuel gas and hydrogen systems to keep the system in balance. Actions are taken to modify unit operations at fuel gas and hydrogen generating units to reduce gas make, if needed (such as changing unit rates and reducing FCCU temperature). In addition, actions are taken to try to increase hydrogen uptake and increase firing at furnaces to consume more of these commodities to keep the fuel gas and hydrogen systems in balance. Typically, the fuel gas system is kept in balance but there are situations when this is not the case. For short periods of time, upsets, malfunctions, emergencies, and other situations can result in the fuel gas system becoming imbalanced until the situation can be stabilized and unit operations can be adjusted to come back into balance. So, efforts to prevent fuel gas imbalance situations apply to all units at the facility whose operation may result in flaring associated with a fuel gas imbalance.

There can be longer-term situations where the fuel gas system is out of balance. For example, there can be situations where the fuel gas producing units are at minimum rate and the fuel gas system is still out of balance. Any further rate reductions would result in the units becoming unstable and pose a safety concern. Actions are taken to minimize the length of time that such situations occur. These situations are infrequent and are generally associated with equipment maintenance/turnaround. Therefore, the duration of maintenance activities is minimized (e.g. overtime authorized), consistent with the work scope and good safety and environmental practices.

Additional information on fuel gas system imbalances is provided in the Startup and Shutdown Process portion of Section 3.4.1, the existing Martinez vent gas recovery, storage, & scrubbing capacities portion of Section 3.4.2, and the description of the wet gas, fuel gas, and flare gas recovery systems provided in Attachment 1.

Beyond this, the Operations shift organization works to maintain good communication and coordination so that the flare gas compressor load is not exceeded. Actions have also been taken to minimize acid gas flaring through monitoring and alarming the molecular weight of the vent gas and taking appropriate action based on that information. An increase in the molecular weight can be an indication that there is an increase in H_2S in the relief header. By monitoring the molecular weight, the operators can be notified of a potential increase in H_2S to the relief header and make operating moves to address the situation more quickly (e.g. reducing H_2S stripping in the stripping column by reducing the stripping steam, which will reduce H_2S to the relief header), resulting in the prevention of or a reduction in acid gas flaring.

The reduction amounts discussed in this section are less than those presented in the 2019 update. This is due to the resulting from the April 2020 decision to place the Martinez refinery in an idle operating state. The amount of waste gas routed to the main flare system is expected to decrease once the safe decontamination of idle process units and equipment has been completed.

3.3 Planned Reductions

A table summarizing the actions currently planned to effect further reductions in refinery flaring is provided in Attachment 6. These items have been identified through flaring evaluations as potential ways to either directly reduce flaring or reduce the chance of a flaring event. The Alky Gas Turbine Replacement project, which replaced the gas turbine with an electric motor, reduced the baseline load to the flare gas recovery compressors due to an improved spillback control system and increased reliability.

Martinez worked on prevention measures to decrease flaring during 5 Gas Plant Turnaround, and to decrease the normal load to the flare gas recovery compressors.

A project identification number has been provided to allow the District to track these projects. The Approval for Expenditure (AFE) number or Project Tracking System (PTS) number has been provided. This is a unique number that is used for accounting purposes and follows the project. In addition, the estimated date of completion of the project has been provided. Please see attachment 6.

Acoustic monitoring on hydrocarbon pressure relief valves are required for the Consent Decree. As leaking components are found, they are added to the turnaround lists for repair. This helps reduce base flow to the flare gas recovery compressors.

As part of the flare causal analysis process, incident teams identified methods that may help to prevent a recurrence of the flaring incident. Many of these items are not key actions to prevent flaring but are actions that may have a potential (even slight) to prevent an incident from recurring. To be conservative, these items are identified because of a lack of information to rule them out as a potential contributing cause to flaring. For example, on the 2/17/2011 flaring incident, flaring was initiated as a result of an emergency shutdown of No. 1 Hydrogen plant, and the depressuring of both stages of the Hydrocracker due to loss of hydrogen from the No.1 Hydrogen plant emergency shutdown. The investigation for this event highlighted several contributing factors, and many of the corrective actions identified in this investigation are related to changes in control strategies, instrumentation, operating procedures, etc. which individually would not eliminate flaring but would potentially reduce the risk of a recurrence. This example illustrates that many of these actions may not directly cause flaring, however, Martinez is committed to studying each action to determine whether implementing them will result in the potential to minimize flaring.

In addition, various potential actions were identified as a part of flare causal analyses. These potential actions are under consideration and are, therefore, not truly "planned reductions" yet. These open action items may yet develop into flare reduction projects but not enough work has been completed yet for them to reach the point of being a planned reduction. These open action items really do not fit in either "reductions previously realized" or "planned reductions" sections. However, Martinez has provided information to allow the District to track these open action items and will include them in the planned reductions section in future FMP updates if they progress to that status. These items are provided in Attachment 7.

Marathon personnel have diligently pursued the completion of feasible actions which would eliminate situations and scenarios which have resulted in past flaring events. However, the August 2020 decision to indefinitely idle the refinery has resulted in outstanding action items previously presented in this plan being rejected since they are no longer applicable in the current operating scenario.

3.4 Prevention Measures

The following section discusses flaring prevention measures and practices utilized at Martinez.

3.4.1 Maintenance Activities Including Startups and Shutdowns

This section discusses refinery maintenance and turnaround activities and outlines measures to minimize flaring during both preplanned and unplanned maintenance activities.

<u>Maintenance Activities</u>

Maintenance activities can 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, in 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 to another point in the processing prior to opening the equipment to the flare or the atmosphere. For example, liquid hydrocarbons can be pumped to tankage or another process system and 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. light cycle oil (LCO). The LCO can then be pumped from the equipment.

Although depressurization and pump-out can normally be used to remove the bulk of the hydrocarbon from the equipment, some residual material can remain. Following pump-out or depressurization to other process equipment, the next step in decommissioning involves sending the residual gas to a fairly low-pressure system that has the ability to accept a wide range of hydrocarbon materials, the refinery wet gas system, where available. This system recovers various gas streams in the refinery.

Lastly, any remaining hydrocarbon is sent to the lowest-pressure recovery system, the flare gas recovery system, so the hydrocarbon can be recovered as fuel gas. This remaining gaseous hydrocarbon can be purged to the flare 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. Steam can be substituted for nitrogen when heat, moisture, vessel temperature, and pressure do not constrain its use. For example, steam cannot be used to purge vessels in caustic service due to the potential for stress corrosion cracking. Steam also cannot be used for most reactors since it would damage the catalyst in the vessel. In addition, some vessels are coated internally for corrosion resistance and steaming cannot be used because it would result in a failure of the coating due to the heat. Substituting nitrogen with steam can produce some small reduction in flaring since the steam condenses in the flare line and is decanted into the refinery slops system, whereas the entire volume of nitrogen goes to the flare.

For any small amount of liquids remaining in equipment, steam or nitrogen are routinely used to push the liquid to the flare system knockout vessel(s). 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 liquid hydrocarbon has been displaced, the flow of steam or nitrogen is continued to remove any residual hydrocarbon clinging to the equipment walls. Steam can be more effective for heavier materials as it increases their volatility by increasing temperature.

Generally, hydrocarbon can be effectively removed from vessels through pumping out the hydrocarbon and purging the vessel with nitrogen or steam. However, when this process is not adequate to clean the vessel for opening, proprietary solutions can be used to chemically clean the vessel. Also, these solutions typically contain materials that are somewhat more hazardous with respect to personnel exposure that nitrogen and steam. Therefore, when nitrogen and steam are effective, those methods are preferentially used.

When used, proprietary solutions are circulated, so that venting is not required. (Nitrogen and steam are once-through purging agents; when purging with nitrogen or steam, the systems being purged must be vented to a flare to prevent pressure from building.) The circulating solution is often filtered to remove contaminants, and fresh chemicals are added as required to maintain solution properties. When the system is clean, the solution is drained, and the equipment is typically flushed with water.

Examples of equipment that might be cleaned using proprietary solutions include pressure vessels, distillation columns, furnaces, and heat exchangers. System components often vary depending on maintenance needs.

Although these procedures eliminate hydrocarbon emissions to the atmosphere related to equipment opening, they require significant volumes of steam or nitrogen in order to be effective. This high flow rate of purge gas can create situations where flare gas recovery is not feasible. These situations relate either to a change in flare vent gas composition (change in molecular weight, heat content, or temperature) or to the increase in vent gas flow rate. Changes in the composition or temperature can be such that the compressors used to recover the vent gas are unable to properly compress the gas. Increases in vent gas flow rate can be such that the compressors cannot recover all the gas.

In addition, there are many process and reactor systems within the 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. This can also result in situations where flare gas recovery is not feasible due to composition or vent gas flow issues (i.e. the amount of flow may exceed the recovery capacity of the recovery system).

<u>Effect of Recovered Flare Gas on Downstream Equipment</u>
Gas composition can impact the operation of flare gas recovery equipment as well as equipment utilizing the recovered gas. Specifically:

- High nitrogen or hydrogen content can impact heaters, boilers, flare gas recovery compressors, and fuel gas compressors.
- Steam impacts knockout drums and compressors, while increasing sour water production.

High hydrogen concentration reduces the Btu value of the fuel gas. If the Btu content drops low enough, this can result in unstable furnace operation and can reduce unit production rates. At the steam boilers, this can result in a significant reduction in steam production and cause an upset in the steam system, which can upset unit operations.

The flare gas compressors are not significantly impacted by higher hydrogen levels, since they are positive displacement compressors. However, high hydrogen concentrations in the gas feeding the centrifugal wet gas compressors (flare gas is recovered and sent to these compressors) affects the performance of the wet gas compressors in that it will drive the compressor closer to its surge curve which can be potentially damaging to the machine.

High flows of nitrogen from equipment decommissioning can lead to a much higher than normal inert content in the mixed flare gas, greatly reducing its heat content (measured as Btu/scf). When this low Btu flare gas is transferred to the fuel gas header, the lower heat content can have the effect of reducing combustion efficiency, as the burners are designed to operate with fuels that have a 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, 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 the use of practices that can lead to this possibility.

The higher than normal nitrogen content of flare gas that can result from nitrogen purging has the effect of greatly increasing its molecular weight. Reciprocating compressors increase the pressure of a constant inlet volumetric flow rate 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.

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 gas will cool, and much of the steam will condense and be removed as water at the knockout 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. Another disadvantage of the use of steam is that most of what is added as a vapor will condense in the flare gas headers and be removed via the water boot of a knockout drum, either as the result of cooling as it flows through a long flare line or in a chiller/condenser included specifically for removal of water vapor from the flare gas. This creates a sour water stream requiring treatment.

<u>Shutdown and Startup Process</u>

During periods of startup and shutdown, a potential for flaring exists. This can be due to several reasons including an imbalance of material producers and users (e.g. fuel gas or hydrogen). Flaring can also occur due to specific startup or shutdown procedures that require venting to the flare system during some portion of the startup or shutdown process. Martinez makes every effort to eliminate flaring from startups and shutdowns. There are, however, situations where this goal is not achieved. Martinez is a highly complex refinery and has a high degree of unit integration. Therefore, the shutdown and start-up of a process unit often affects one or more units upstream or downstream, and in some cases the entire refinery.

As a processing unit is shut down, rate is typically reduced to minimum, and the operations of other affected units are adjusted accordingly in a controlled fashion. Typically, minimum rate is about one-half of a unit's design capacity, and is determined by equipment constraints. When the unit ultimately does shut down, meaning feed to the unit is reduced from minimum to zero, imbalances may occur at other units that are upstream or downstream, or in the refinery as a whole. Flaring can often be prevented, but in some cases the operations of the units that are affected cannot be adjusted quickly enough (due to mechanical and process limitations), and excess material must be flared to avoid over-pressuring equipment. During unit start-ups, similar situations can occur.

For example, when a catalytic reforming unit is started up, hydrogen is initially produced more quickly than can be consumed in the refinery, and the excess hydrogen must be flared until operations can be balanced. Similarly, when a catalytic reforming unit is shut down, some amount of excess hydrogen must be produced at other hydrogen-producing units in advance to compensate for the loss that is about to occur. Once the unit has been shut down, operations can be balanced, and flaring stops. In some situations, part of the excess hydrogen required in start-up and shutdown situations can be routed to the refinery fuel gas system up to the operating limits of that system.

At the Chemical Plant, start-up and shutdown procedures involve sending gas to the flare via the relief scrubber. This is done to ensure personnel safety prior to maintenance activities and to protect equipment prior to re-commissioning. On shutdown, equipment is purged with steam to the relief system to ensure a safe environment for personnel entry during maintenance and inspection tasks. On start-up, air is purged from the unit using steam or nitrogen. The difficulties associated with recovery of Chemical Plant flare gas is discussed in the Existing Systems for Vent Gas Recovery portion of Section 3.4.2.

Analysis of Prior 5 years of Major Maintenance Related Flaring
A review of the last 5 years of maintenance related flare events was conducted. Due to the time that has passed for many of those events, it was difficult to gather enough specific details of the situation (e.g. when purging started and stopped, vessels were opened, etc.) to develop specific findings. However, a review of the data confirms that vessel depressurization and purging, fuel gas system imbalances, and hydrogen system imbalances account for the majority of the flaring related to major maintenance activities. Provided below is an analysis of the major maintenance related flaring and the FMP planned prevention measure associated with each cause.

Historic Major Maintenance Flaring Analysis

Flaring events related to major maintenance were reviewed and the primary cause of the flaring for those events was grouped into 5 main categories. Those categories are: 1) hydrogen system imbalance, 2) flare compressor shutdowns, 3) fuel gas system imbalance, 4) shut down of the No. 5 Gas Plant, and 5) general flaring related to unit shutdowns. Each of these causes are discussed below, along with the method proposed in the FMP to address those situations.

Hydrogen System Imbalance

This cause contributed to about 1% of the major maintenance related flaring incidents between 2015 and 2020 which were reviewed.

Primary Cause of the Flaring

An imbalance in the hydrogen system can occur when the production of hydrogen is out of balance with hydrogen consumption at various units. This can occur during startup and shutdown situations at hydrogen producing or consumption units. Typically, when a hydrogen consumption unit is shutdown, the production of hydrogen can be reduced concurrently to ensure that the hydrogen system stays in balance. However, during a startup of a hydrogen producing unit, the hydrogen producing unit is brought on line and the hydrogen is sent initially to the flare header, so the hydrogen consumption units are not impacted by the startup. Those impacts can be related to low hydrogen purity during startup or the stability of unit operations due to varying hydrogen quantities. This results in several hours of flaring until the hydrogen product meets the quality specifications.

For example, Air Products operates a 35 MMSCFD Hydrogen Plant that is located inside the Martinez fenceline. Air Products normally produces utility hydrogen, which is sold exclusively to the Martinez. During start-up, feed is introduced into the unit and the unit begins producing a low purity hydrogen product. This product contains 75% hydrogen, 16% CO_2, 3% CO, 6% methane and other impurities. This low purity hydrogen product cannot be used in Martinez as it contains contaminants that could permanently poison catalyst in other refinery catalytic process units (e.g. No. 3 HDS, Hydrocracker, etc.). As a result, the hydrogen is directed to a flare until the product hydrogen purity of 99% is achieved.

After the initial step of introducing feed, the Pressure Swing Absorber (PSA) skid is then placed in service to increase hydrogen purity and remove contaminants. It takes approximately 4 to 6 hours to line out the filtration system. Once the hydrogen reaches an acceptable purity, Air Products personnel notify the Martinez 's shift organization and the hydrogen is gradually introduced into the 400 lb hydrogen header. These types of units produce both CO and CO_2 as by-products. Since both of these carbon oxides can inhibit hydrodesulfurization reactions, hydrogen produced at either No. 1 or No. 2 Hydrogen Plant is not suitable for use as make-up for hydrogen-consuming units until the level of CO plus CO_2 is less than 50 ppm. This specification is confirmed by an on-line analyzer at No. 2 Hydrogen Plant. At No. 1 Hydrogen Plant this specification is confirmed by laboratory analysis and can be inferred by methanator differential temperature.

In 2017 Air Products modified their startup procedures such that the Air Products startups do not normally exceed 500,000 SCF of flaring.

Hydrogen produced at catalytic reformers like No. 2 and No. 3 Reformers does not contain CO or CO_2, and can normally be routed to the refinery soon after the introduction of feed, provided it is free of inert gases like nitrogen that may have been used to purge equipment.

Minimum rate at No. 2 Hydrogen Plant is about 18 MMSCFD, so that is typically the amount of hydrogen that must be flared until the level of CO plus CO_2 is less than 50 ppm. At No. 1 Hydrogen Plant, minimum rate is approximately 35 MMSCFD, and once again, that is the amount of gas that must be flared until the hydrogen is on-spec.

During start-ups, the volume of off-spec hydrogen produced is too great to be handled by the refinery fuel gas system. Routing all of the off-spec hydrogen that is produced during start-up of either No. 1 or No. 2 Hydrogen Plant to the fuel gas system could potentially cause that system to become unstable and over pressure. Additionally some of the by-products produced during hydrogen plant start-ups, like CO and CO_2, are not suitable fuel gas components.

The number of hydrogen plant start-ups per year varies, but averages about two to three times per year. Efforts to reduce unplanned shutdowns to a minimum are ongoing. They include the maintenance and inspection programs mentioned in Section 3.4.3. In addition, attempts are in progress to extend the boiler inspection interval (state mandated) to reduce plant shutdowns. Further, the contract with Air Products includes provisions for on-stream efficiency.

No. 1 and No. 2 Hydrogen Plants are shut down to inspect equipment, service relief valves, change catalyst, and re-new boiler operating permits. Also, hydrogen plant shutdowns can occur due to unit upsets and/or equipment malfunction. In addition, the No. 1 Hydrogen Plant may also be shut down to balance the refinery hydrogen system if a major hydrogen consumer like the Hydrocracker were to be shut down.

Hydrogen Plant planned turnaround dates are driven by the need to inspect equipment, service relief valves, change catalyst, and re-new boiler operating permits, and cannot be extended beyond the required frequencies for these activities.

The Martinez refinery has not identified a way to introduce low quality hydrogen (i.e. high levels of CO and CO_2) into the hydrogen header due to the adverse impact on the catalyst in downstream units. Attempts are made to bring the No.1 and No. 2 Hydrogen Plants up to full quality as quickly as possible (by bringing the methanator at No.1 Hydrogen Plant and the PSA unit at No.2 Hydrogen Plant on quickly) to minimize flaring.

At Martinez, hydrogen is distributed from the hydrogen-producing units to the hydrogen-consuming units via a system of pipes that operates at about 400 psig. To avoid flaring, feed rates and other operating parameters at these hydrogen producing and consuming units are adjusted on a regular basis to maintain a balance. The start-up of a major hydrogen-producing unit like No. 1 Hydrogen Plant is typically planned and executed so that it coincides with the start-up of a hydrogen-consuming unit like the Hydrocracker. This practice reduces flaring by maintaining the balance between production and consumption. During unplanned situations, the startup and shutdown of hydrogen producing and consuming units may not coincide.

During the shutdown and start-up of the No. 1 Hydrogen Plant, a portion of the hydrogen produced is recycled back into the hydrogen plant to avoid flaring. The hydrogen plant shutdown procedure has been revised, and this new technique was used successfully when the unit was shut down recently.

<u>Actions to Minimize or Eliminate Flaring during this Situation</u>
The following actions have been identified to minimize flaring associated with the startup of hydrogen production units:

- Try to minimize the number of required plant start-ups each year, achieving a high plant on-stream efficiency and extending turnaround dates. This action is already in place.
- Coordinate the start-up of hydrogen production units to insure product is used, when available, to minimize flaring. This action is already in place.

<u>FMP Planned Prevention Measure</u>
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

<u>Flare Compressor Shutdowns</u>
This cause contributed to about 1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

<u>Primary Cause of the Flaring</u>
The flare recycle compressors can shut down for various reasons. This can occur due to high oxygen content in the flare gas or for planned maintenance on the compressors. The flare compressors can also be purposely shut down when the flare gas quality is such that it could result in damage to the compressors or could cause gas quality problems in the fuel gas system. The compressors may also be shut down when there is more fuel gas available than there are fuel gas consumers, so recycling the flare gas to fuel gas system is not feasible.

If the oxygen content of the flare gas gets too high, the flare gas recovery compressors will automatically shut down to prevent the development of an explosive mixture in the system. Also, the flare recovery compressors and associated equipment may need to be shut down to perform maintenance. In addition, there are situations when the flare gas quality is such that the molecular weight of the flare gas could be low enough to damage compressors in the system that cannot handle lower molecular weight gases or the composition of the flare gas is such that it could impact the fuel gas quality and result in upsets at the furnaces burning the fuel gas. The fuel gas compressors could also be shut down if the fuel gas balance is such that there is excess fuel gas and recycling the flare gas would simply overpressure the fuel gas system and send the gas right back to the flare. This last situation is discussed further in a later portion of this section.

In each of these situations, the flare recycle compressors are no longer available to recover flare gas, and that gas is sent to the flares.

The oxygen in the flare gas primarily comes from the vapor recovery system which consists of atmospheric tanks and the marine vapor recovery system. Also, some minor amounts of oxygen can enter the system from the Merox Treating Unit. In the event of a high oxygen level in the flare gas, enrichment gas (propane) would typically be added to reduce the oxygen concentration. For example, if a tank PV valve is not operating properly, air can enter the system. If there is an unintended opening in the marine loading system (e.g. a vessel hatch, etc.), air can also enter the vapor recovery system. The refinery has not succeeded in preventing this from occurring at all times. Once the situation occurs, action can be taken, as noted above, to add enrichment gas.

The flare recovery compressors are positive displacement compressors and are not sensitive to molecular weight. Nonetheless, the flare flow meters include molecular weight on each flare header and an oxygen analyzer. Occasionally, both machines need to be shut down together when work is required on a part of the system that is common to both compressor trains such as the recovered gas knockout pot.

<u>Actions to Minimize or Eliminate Flaring during this Situation</u>
The following actions have been identified to minimize flaring associated with the shutdown of the flare recycle compressors:

- Continue to monitor compressors under rotating equipment, reliability, and inspection programs to reduce chance of an unplanned outage
- Schedule planned maintenance on one compressor at a time as much as possible
- Monitor flare vent gas oxygen levels and take action to try to keep oxygen levels low
- Maintain flare vent gas oxygen monitors to reduce the chance of monitor malfunctions that could shut down the flare gas recovery compressors

<u>FMP Planned Prevention Measure</u>
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will

be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

Fuel Gas System Imbalance
This cause contributed to about 0.1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

Primary Cause of the Flaring
An imbalance in the fuel gas system can occur when the production of fuel gas is out of balance with fuel gas consumption at various units. This can occur when significant fuel gas combustion equipment is shut down while major fuel gas producing units are still online. This can occur for short periods when equipment is being taken off line, until the fuel gas system can be brought back into balance. This can also occur for longer periods of time if, after reducing fuel gas producing units to minimum operation, there is still more fuel gas generated than consumption demand.

The Martinez refinery makes every effort to eliminate fuel gas imbalance situations. There are, however, situations when that goal is not achieved. An example of this would be if a maintenance turnaround is required to meet a regulatory compliance deadline that would not fit into a normally scheduled maintenance turnaround schedule.

In addition, there are situations when the balance of fuel gas production and consumption for a specific set of operating units cannot be attained by manipulating the rate/severity of those units within their maximum and minimum rates. For example, when the No. 5 Gas Plant is down and the FCC is in operation, the No. 4 Gas plant cannot handle all the wet gas produced by other units, even with the FCC at minimum rate and severity.

Also, increasing fuel gas consumption when doing so would negatively impact the balance between unit products and feeds (when more is produced by one unit than can be fed to the downstream unit, or stored) is unlikely to reduce flaring. Additionally, increasing fuel gas consumption can negatively impact regulatory requirements such as the Regulation 9, Rule 10 NOx cap or other limits.

Actions to Minimize or Eliminate Flaring during this Situation
The following actions have been identified to minimize flaring associated with fuel gas system imbalance situations:

- Coordinate major equipment maintenance shutdowns, to the extent feasible, to minimize or eliminate fuel gas imbalance situations
- Should fuel gas imbalance situations still occur, try to reduce fuel gas production to minimize or eliminate the fuel gas imbalance situation
- Should fuel gas imbalance situations still occur, try to increase fuel gas usage to minimize or eliminate the fuel gas imbalance situation

FMP Planned Prevention Measure
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the

refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

No. 5 Gas Plant Shutdown
This cause contributed to about 1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

Primary Cause of the Flaring
The flare gas recovery compressors return the recovered flare gas to the No. 5 Gas Plant, where it is compressed further, treated, and sent to the fuel gas system (see Attachment 4 for a diagram of the flare gas recovery system). When the No. 5 Gas Plant is shut down for scheduled maintenance, there is no way to recover the flare gas.

When No. 5 Gas Plant is shutting down for a turnaround, the FCC is brought to minimum rate in order to make room in No. 4 Gas Plant for the extraneous gas streams that normally go to No. 5 Gas Plant. During this time the rates to refinery units are reduced, No. 4 Gas Plant capacity is at its maximum and is not able to run all the gas produced.

The following actions have been taken to reduce No. 5 Gas Plant turnaround duration: 1) scope reviews are held prior to each turnaround, which include efforts to minimize turnaround duration, and 2) detailed planning and scheduling of each turnaround is conducted to minimize turnaround duration.

Although these actions are routinely taken, it may not be possible to reduce the duration of the turnaround due to the work scope which needs to be completed to address mechanical integrity, performance, or regulatory requirements.

Actions to Minimize or Eliminate Flaring during this Situation
The following actions have been identified to minimize flaring associated with the shutdown of the No. 5 Gas Plant:

- Prior to a No. 5 Gas Plant shutdown, as a part of the turnaround pre-planning process, determine if there are feasible actions to reduce the amount of flare gas being generated
- As a part of the turnaround pre-planning process, determine if there are feasible actions to reduce the length of the No. 5 Gas Plant turnaround
- Consider the feasibility of other routing options for flare recycle gas during No. 5 Gas Plant shutdowns

FMP Planned Prevention Measure
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes

pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

General Flaring Related to Unit Shutdowns

This cause contributed to about 96% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020. This period included a refinery-wide strike between February and April 2015, and the ongoing refinery idling event which started in April, 2020

Primary Cause of the Flaring
During major maintenance, various activities can result in flaring. This can be due to increased flow of vent gas to the flare gas system that exceeds the system's ability to recover the flare gas. This can also be caused by a change in the quality of the flare gas (such as high nitrogen content) that results in the flare gas being unsuitable for recovery as fuel gas. These situations can result from the depressurization of vessels, purging of vessels to the flare system, and during periods of equipment start up and shut down when gas is being sent to the flare system.

Unit, system, and vessel depressurization and purging operations are controlled to minimize flaring by regulating the rate at which depressurization occurs. This is accomplished by throttling the valves that are used to control depressurization rates. Flow meters at the flares are monitored to verify that depressurization rates are not excessive. Multiple depressurizations are typically staggered to reduce the possibility of flaring and are coordinated by the Shift Superintendent. Flaring is reduced by monitoring the rate at which equipment is depressured to the flare and adjusting the depressurization rate as needed to try to stay within the flare gas recovery system capacity.

In general, the refinery stays within the ability of the flare gas recovery system when shutting down and purging refinery units. However, situations can arise where the capacity of all the compressors is exceeded. For example, the flow rate of nitrogen needed to properly clear a reactor vessel (and catalyst) of hydrocarbon can exceed the ability of the flare gas recovery system to recover the gas. In those cases which involve large amounts of process units being shutdown or idled, as was the case with the 2015 USW strike and the 2020 refinery idling event, process combustion sources which normally receive recovered flare gas are no longer available. Flaring events will commence once the rate at which gas is routed to the main flare system exceeds the rate at which it can be combusted by these sources.

Actions to Minimize or Eliminate Flaring during this Situation
The following actions have been identified to minimize flaring associated with general shutdown related flaring:

- Control vessel depressurization and purging vent gas sent to try to stay within the recovery ability of the flare system.
- For events which necessitate the shutdown or idling of the refinery or large numbers of process units, stage the shutdown of individual combustion sources to maximize flare gas recovery, finishing with the shutdown of the No. 5 Gas Plant.

FMP Planned Prevention Measure

The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

Summary

The Martinez refinery has performed each of the listed major maintenance activity types without flaring. As a result of this examination, it was determined that, for each major maintenance activity, the pre-turnaround planning process will be used to minimize or eliminate flaring on a case-by-case basis, including reducing process flow rates (see more detailed description in Description of Planned Prevention Measures section below). Considering that each turnaround is unique (i.e. what units will be shut down, the order of the shutdown, the extent of the shutdown and maintenance or other actions that need to be performed, etc.), Martinez believes that this will provide the best opportunity to eliminate or reduce flaring. This process has been used in recent turnarounds and has yielded good results in reducing or eliminating flaring.

Additionally, Martinez looked at the feasibility of providing additional compression, storage and treatment options to minimize flaring due to issues of gas quantity and quality. These options were determined to be infeasible based on cost (see section 3.4.2).

Description of Planned Prevention Measures

As a part of the planning process for maintenance activities, Martinez includes the consideration of what actions could be taken to eliminate or reduce flaring resulting from those activities. The method used to consider flare minimization actions varies depending upon the nature of the maintenance.

Planned maintenance turnarounds are typically scheduled and planned many months to years in advance. For planned maintenance turnarounds, appropriate Operations and Maintenance personnel will conduct a pre-turnaround evaluation of potential flaring that may occur as a result of the specific turnaround being planned and consider actions that could be taken to either eliminate flaring or minimize flaring from those activities. At a minimum, the bulleted measures identified below are considered during the pre-turnaround planning process, including rate reductions.

Consistent with this FMP, potential prevention measures to eliminate or minimize flaring will be considered in light of the technical, safety, regulatory, and cost impacts associated with the measure. Measures will be implemented, consistent with good safety and environmental practices, and which can be performed in a cost effective manner.

This process has been used in recent turnarounds and has yielded good results in reducing or eliminating flaring. This process is documented in a procedure which is followed for planned major maintenance activities.

This procedure includes a post-turnaround evaluation. When the turnaround is complete, Martinez evaluates which flare elimination and minimization actions were effective and which were ineffective. Since the majority of flare minimization results from planning unit shut down sequences and vessel depressurization timing, the refinery can review the shutdown timeline of events vs. flaring activity to determine if that particular plan of activities produced less flaring. From that evaluation, a set of recommendations are developed for consideration for the next turnaround planning effort for that equipment.

These planning sequence documents are available at Martinez for District review. This allows the District to verify that the planning process was followed and to ensure that appropriate actions were taken to eliminated or minimize flaring.

For routine maintenance activities, Martinez considers how to avoid or minimize flaring as part of our work practice.

All events of significance as noted in Regulation 12, Rule 12 (i.e. all reportable flare events) are evaluated to determine whether flaring could be eliminated or reduced from such events. Conducting causal analyses for extremely small flaring events is difficult and emissions from such small events are so low that it is not reasonable or cost effective to conduct a causal analysis. Very small flare events are, by their very nature, either very low flow events and/or very short in duration. In general, it is not possible to determine the cause of such events due to their brief, low flow nature.

Occasionally, maintenance must be performed with very short notice. This is usually due to concern regarding potentially imminent equipment failure or to address a safety concern. Due to the short time allowed to conduct the maintenance, there is not typically time to conduct an analysis of potential flaring impacts. For such unplanned maintenance, if a reportable flare event occurs as a result of the maintenance work, a causal analysis would be conducted and would consider what action should be taken to prevent or minimize flaring in the future from that maintenance activity.

Measures to Minimize Flaring During Preplanned Maintenance
Examples of measures that would be considered to eliminate or minimize flare emissions are provided below:

- Depressuring to other closed systems first to minimize material sent to the flare system
- Depressuring to the flare system slowly to help stay within the flare recovery system capacity
- Modify unit operations at fuel gas generating units to reduce gas make and keep the fuel gas system in balance (such as changing unit rates and reducing FCCU temperature)
- Increase firing at furnaces to increase gas consumption and keep the fuel gas system in balance
- Use of chemicals to improve initial hydrocarbon removal to reduce the time needed for steam out or purging to flare
- Route gas streams with significant hydrogen content to the Hydrogen plant for hydrogen recovery instead of being routed to the flare.
- Shutdown activities are staged to keep the rate to the flare gas system within the recovery capability
- Maintain good communication and coordination within the Operations shift organization so that the flare gas compressor load is not exceeded.
- Feed and product compressors are used to recycle material during startup until product specifications are met, allowing flaring to be avoided.

The measure to route the depressurized or purged gas slowly to the flare gas recovery is a general practice, but has not been incorporated into all shutdown procedures. As the shutdown procedures are revised, this will be incorporated into those procedures.

Operations of units that produce fuel gas range materials are adjusted, including at times reducing severity of operations in the process unit (e.g. FCC), to reduce fuel gas production if it would put the refinery in a flaring situation. Specifically, actions are taken to reduce FCCU unit rate and/or operating severity (i.e. reduce the reactor temperature) to reduce overall refinery gas production.

There are three feed/product compressors. Each compressor has a capacity on the feed side of approximately 8 MMSCFD and on the product side of about 30 MMSCFD. The use of feed and product compressors to recycle material during startup or shutdowns until product specifications are met is specific to the No. 1 Hydrogen Plant and is considered as a part of the pre-planning process as noted in Section 3.4.1. To the extent that this appears to be a method that can be used in essentially all startups or shutdowns, it will be incorporated into the procedures. This has already been incorporated into the Hydrogen Plant shutdown procedures. If there is still uncertainty on whether this can be done routinely (i.e. whether this can be done is dependent on the specific planned major maintenance situation), then the procedures would not be modified, but the method will continue to be considered during the pre-planning for the planned major maintenance.

In general, these measures will be performed provided the equipment required to perform them is available. It is, of course, impossible to identify all situations that preclude the use of one or more of these actions. However, an example of such a situation would be the use of chemicals to improve initial hydrocarbon removal in reactor vessels that contain catalyst, since the chemical would damage the catalyst. Another example would be that all equipment may not have connections to the wet gas system which would make it impossible to route gases to other closed systems before sending it to the flare.

All these measures reduce flaring by sending gases that might normally be routed to flare to other locations where they can be recycled or processed.

50 Unit Flare
The 50 Unit flare was designed so that there would be no flaring during normal startups and shutdowns. The 50 Unit flare gas recovery system compressor is sized for complete recovery of the vapors during normal operations, and during de-pressuring and steam-out of smaller equipment for maintenance. The existing spare 50 Unit wet gas compressor is lined up and used for recovery of the vapors during de-pressuring and equipment steam-out of larger process equipment. The existing spare wet gas compressor will also serve as a common spare between the flare gas recovery service and the wet gas service. Instrumentation and controls have been provided to enable switching of an existing spare wet gas compressor from wet gas service to the vapor recovery service, after proper line-up. Since equipment de-pressuring and steam-out operations are well planned operations, sufficient time is available for changing over from the small flare gas recovery system compressor to the existing wet gas compressor and vice versa. Control valves have been provided on the steam-out lines from large process equipment for controlling steam-out rates to minimize the chance that the 50 Unit Flare liquid seal would be broken during the steam-out operations. A pressure control valve upstream in the compressor suction line will maintain a constant pressure in the flare gas recovery system, by discharging all vapors from normal venting (purges), equipment de-pressuring and steam-out for maintenance, into the refinery fuel gas system, through the wet gas compressor and the wet gas header.

3.4.2 Gas Quality and Quantity

This section discusses when flaring is likely to occur, systems for recovery of vent gas, and options for recovery, treatment and use of flare gas.

Releases of vent gas to the flare can 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. In addition, releases of vent gas to the flare can result from a change in vent gas composition that either makes it infeasible to compress or infeasible to burn 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.

Maintenance Activities Including 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
- Leak repairs
- Compressor repairs
- Unit Startup

Each of these activities 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 or consumed by other units cannot be made quickly enough, then flaring results.

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. This has been discussed in Section 3.4.1.

<u>Malfunctions and Upsets</u>
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:

- Relief valve releases, leaks, or malfunctions
- Loss of a major piece of equipment (pump, compressor, etc.)
- Loss of fuel gas or flare gas recycle compressors
- Loss of a utility (steam, cooling water, power)
- Loss of air fin fans or condensers

These examples can be caused by equipment malfunction, outside entities, operator error, or various other causes. Each of these bullet items can result in flaring, to the extent that the amount of gas exceeds the flare gas recovery system capacity or the composition of gas precludes its use as fuel gas. For example, if a relief valve relieves to the flare, the flow can be greater than the capacity of the flare gas recovery system, resulting in flaring. The loss of a major piece of equipment can result in a unit shutdown which can send high volumes of gas to the flare system or send high concentrations of hydrogen to the flare system, resulting in flaring. If the flare recycle compressors trip, the gas cannot be recovered and would result in flaring. Losses of electricity or other utilities, as well as losses of other equipment can result in unit upsets that require vent gas to be sent to the flare as a safety measure, which will again result in flaring.

<u>Emergencies</u>
Various situations can result in events that require immediate corrective action to restore normal and safe operation. Emergency flaring events are defined by Regulation 12-12-201.

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. This can be caused by high normal flows of vent gas to the flare or by limited flare gas recovery capacity. High normal flows refers to situations where the routine flow of gas to the flare system is higher than usual. This would reduce the amount of additional gas that could be sent to the flare system before the flare gas recovery compressor capacity would be reached, resulting in flaring.

Reduced Consumption of Fuel Gas

If flaring is to be minimized, it is necessary to balance fuel gas producers and consumers in the refinery. Situations that reduce fuel gas use can limit the amount of vent gas that can be recycled. Reduced fuel gas use can result from energy efficiency projects that reduce fuel gas consumption or equipment temporarily shutdown. As the energy efficiency of furnaces or boilers is increased, less fuel is used (i.e. less gas is burned for the same operating rate. As the fuel use is reduced, more fuel is available in the fuel gas system. The types of energy conservation projects that can reduce fuel gas use include efforts to minimize oxygen levels in furnaces and boilers, and efforts to optimize distillation tower reflux.

Other Causes

There can be other occasional situations that result in flare vent gas composition or quantity impacts that can be potential causes of flaring. These tend to be infrequent and can be exceedingly difficult to totally eliminate, despite careful planning and system design.

Vent Gas Recovery Systems

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 recovery compressor system. The compressed gases are 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.

The capacity of a flare gas recovery system is generally taken as the total installed nameplate capacity of the flare gas compressor. However, flare gas compressor capacity does not fully define the practical total capacity of the system. The ability of the flare gas recovery system to recover the gas and use it as fuel gas is practically limited by three things: 1) the flare recovery gas compressor capacity, 2) the fuel gas treating capacity, and 3) the ability to consume the additional fuel gas. The most constraining of these three items at any point will dictate the practical flare gas recovery system capacity.

Existing Systems for Vent Gas Recovery

The main refinery flare system has a flare gas recovery system that recovers and compresses the flare gas, sending it to the No. 5 Gas Plant where it is further compressed, sent through an amine treater and then sent to the fuel gas system. A diagram of the Martinez flare gas recovery system for the main flare system is provided in Attachment 8.

The ARU Flare does not have a vent gas recovery system. The reuse of ARU Flare gas is not possible due to the variation and hazardous nature of the material sent to the flare. The material that can be sent to the ARU Flare includes steam, nitrogen, ammonia, H_2S, and air. Due to this wide variation in material, there is no reasonable location that this material could be sent for recovery. For example, sending air, ammonia, or high amounts of H_2S into a fuel gas system would not be appropriate and could result in safety and/or operational issues (such as furnace upsets). In addition, due to the potential for high H_2S and/or ammonia levels in the flare gas, the potential for personnel exposure would be increased by redirecting these streams. The potential for leaks using rotating equipment would also pose a potential safety issue.

Gases from the relief header are fed to the relief scrubber where they are contacted with a continuously circulating stream of ammonia solution. This solution absorbs H_2S and ammonia with the resulting overhead vapor flowing to the flare. Circulation of the ammonia solution is maintained by a scrubber pump on a continual basis. Should a large relief load be present, a second larger circulation pump is started which increases scrubbing capacity by 2.7 times. The rich circulating solution is purged from the scrubber and sent to the feed mixing drum for reprocessing through the ARU. The scrubber itself is designed with two compartments. The first is used during normal operating conditions whereas the second is used during upset conditions when extra H_2S and ammonia absorbing capacity is required. Absorption capacity is limited by the size of the compartments, volume of the circulating ammonia solution, sizing of the existing pumps, storage capacity for the purged rich solution and hydraulic capacity (i.e. residence time) of the gases in the scrubber.

Therefore, the discussion below will focus on the feasibility of additional vent gas recovery for the main refinery flare system only.

Existing Martinez **vent gas recovery, storage, & scrubbing capacities (Main Flare & ARU Flare)**

A summary of the existing vent gas recovery, storage, and scrubbing capacity is provided in the table below:

Flare System	Flare Gas Compressor Capacity (MMSCFD)	Storage Capacity (MMSCF)	Scrubbing Capacity for Vent Gas (MMSCFD)	Total Gas Scrubbing Capacity (MMSCFD)
Main Flare System	4	0	4	60
ARU Flare *	0	0	2.3	2.3

*The Ammonia Plant Flare is dedicated to the Ammonia Plant/Sulfur Plant/Sulfuric Acid Plant. Due to the nature of the vent gases, there is no vent gas recovery equipment for this flare. However, there is a vent gas scrubber associated with this flare. The scrubber capacity of 2.3 MMSCFD is based on recovery of pure H_2S and can only be achieved for a short period of time.

The Martinez vent gas recovery system does not include any dedicated capacity for storage of fuel gas or vent gas. However, on a continuous basis Martinez 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, propane, and butane (or other refinery fuel sources). For example, the amount of purchased natural gas is adjusted to maintain the target fuel gas pressure. In addition, propane and butane are added, as needed, to increase the Btu content of the fuel gas. If there is a fuel gas system imbalance situation and the Btu content is acceptable, this material would not be added to the fuel gas system. These adjustments are made whenever the fuel gas system approaches getting out of balance. However, these efforts are not always successful, depending upon the operating situation at the time and there is no way to ensure Martinez is always in fuel gas balance;

- Adjusting the operations of units that produce fuel gas range materials including at times reducing severity of operations in the process unit (e.g. FCC) 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 maximizing export of fuel gas to the third party cogeneration unit (within their operating constraints), maximizing steam production from refinery steam boilers, shifting rotating equipment to turbine drivers where feasible (which operate with steam generated in the fuel gas fired boilers), and at times reducing the throughput of processing units to minimize gas production. Fuel gas consumption is not maximized at all times because using more fuel gas than is absolutely necessary results in higher emissions and energy inefficiency. Rotating equipment can utilize steam or electricity to turn the equipment. In various locations throughout the refinery there are rotating equipment with a primary and spare and where the primary and spares are on different motive force (i.e. one using electricity and one using steam). In those locations, if the electric driver is in use, the spare equipment can be put on-line using steam, which will increase the steam use in the refinery. That, in turn, will result in an increase in firing at the refinery boilers, resulting in additional fuel use. If more fuel gas is being produced than consumed, this can help balance the fuel gas system, albeit in a limited fashion. Any additional firing at the boilers will reduce the amount of excess fuel gas being sent to the flare, in an excess fuel gas situation, resulting in reduced flaring

The total gas scrubbing capacity that is indicated is an integral part of the refinery fuel gas management system. This capacity is closely matched with the fuel gas consumers' (heaters, boilers, etc.) usage requirements. The capacity indicated as being available for recovered vent gas scrubbing will vary depending on the balance between fuel gas production and consumption; it will vary both on a seasonal basis and during the course of the day. For this reason a range is provided indicating the approximate minimum and maximum available capacity.

Options for Recovery, Treatment and Use

To address the requirements of Regulation 12-12-401.4, Martinez 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.

The flare header is connected to both a flare gas recovery system and to several 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 plant where it is further compressed and treated to remove contaminants such as sulfur. The treated gas is then sent to the refinery fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressors, the gas plant, the gas treating system, 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, the following essential infrastructure elements must be considered whether:

- additional compressor capacity (at the flare area or at the gas plant) would be needed to increase vent gas recovery,
- additional capacity in treating systems would be needed to increase vent gas recovery, and
- there are sufficient end users for an increase in recovered and treated gas

In addition, providing sufficient storage volume to dampen out the variation in volumetric flow rate to the flare gas header could potentially reduce the volume of gas flared.

Compressor Capacity

Compressors are used to increase the pressure of the vent gas from near atmospheric pressure to the pressure of the wet gas system. The flare gas recovery compressors located in the flare area compress the vent gas to a pressure that allows the gas to be sent to the No. 5 Gas Plant. The No. 5 Gas Plant wet gas compressors increase the pressure further to send the gas to an amine treater and then to the fuel gas system. In order to recover additional vent gas it is necessary to have sufficient capacity in both the existing flare gas recovery compressor capacity and the wet gas compressors at the No.5 Gas Plant to match the desired vent gas recovery flow.

Treating System

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 (see also the discussion of fuel gas quality in Attachment 1). 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 flow rate of the flare gas requiring treatment. Even if the capacity for treating is large, managing a large increase in flare gas needing treatment is problematic. It is difficult, if not impossible, to increase treating flows as quickly as flare flows can increase.

This is because the capacity of gas treating systems must match the peak flow rate of the flare gas requiring treatment. The peak flare gas flow can exceed a rate of 50 MMSCFD and this rate can be achieved in a matter of 10 minutes or less. Such treating systems are designed for a specific flow rate (i.e. a design velocity of vapor traffic through the treater). Such systems also have a minimum turn-down rate (i.e. the rate at which the system will still function reasonably to treat the gas). Those turndowns are typically only about 25% or so. Therefore, such a treater would not effectively treat flows below about 37 MMSCFD. If the treater is sized smaller, it would not be able to handle the peak flow and could result in a loss of the liquid in the treater due to excessive vapor velocities.

End Use Capacity

End use capacity can be the limiting factor on the amount of flare gas that can effectively be recovered. Many refineries operate relatively near fuel balance (i.e. the amount of fuel gas generated is close to the amount of fuel needed for the various processes). There is typically a small amount of natural gas added to the fuel gas system to maintain pressure control. During period of significant flaring, the ability to practically recover and reuse the flare gas is often limited by end use capacity. There is typically not enough additional combustion capacity to consume a large increase in available gas. In addition, many of these situations are due to a significant upset or emergency situation which also makes accommodating the additional fuel gas difficult.

Storage

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, both the selection of an acceptable site and obtaining the permits necessary for construction present difficulties. Despite the refinery's demonstrated commitment and strong track record with respect to safe handling of hazardous materials, the surrounding community is expected to have concerns about any plan to store large volumes of flammable gas containing H_2S 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.

Evaluation

A consultant, ENSR, was used to conduct the evaluation and this information was reviewed by Martinez. In order to assess the feasibility 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: 1) the rate of flow of additional flared gases that could be recovered, 2) the modifications required to achieve that recovery, and 3) 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.

The evaluation is based on the need for installation of three 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 un-spared compressor system to be added to the flare gas recovery system. The estimate is for a reciprocating compressor with all necessary appurtenances for operation, that is, knockout 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 at the identified flow rate, 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. For the large storage volumes needed for some of the options considered, the cost is based on the use of multiple spheres.

- 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. Installed cost data for new treatment systems was scaled to estimate the cost of adding treatment for each of the two flow rates identified below. 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.

The table below presents a summary of estimated total installed capital costs for various treatment capacities and scenarios.

Treatment Capacity (MMSCFD)	Additional Vent Gas Compressor Capacity	Surge Storage (24 hrs. at flow rate)	Providing Incremental Additional Gas Treating for This Flow	If Additional Compressor, Storage and Treating Capacity Added
2.0	$3,600,000	$5,000,000	$2,000,000	$10,600,000
4.0	$6,700,000	$10,300,000	$3,500,000	$20,500,000
100.0	$160,800,000	$250,800,000	$6,000,000	$417,600,000

In addition to estimating the type and cost of equipment that would be needed to recover additional flare gas, an evaluation was conducted of how much flare gas could practically be recovered using such systems along with an analysis of the anticipated emission reductions for each case. The key points of the evaluation are summarized below:

- The 2005 flaring data has been reviewed and, based on the monthly flare report data, the non-methane emissions per standard cubic foot (scf) of flared gas is 0.00019 lb of non-methane hydrocarbon per scf. This is based on sampling data from reportable flaring events, the flare gas flow data, and applying a 98% combustion efficiency for hydrocarbon.

- Daily average flaring data has been reviewed for the previous calendar year (2005) leading to the conclusion that, on an annual basis, the addition of 2 MMSCFD of additional (unspared) compressor system (including storage and treating) capacity would capture approximately 118 MMSCF of gases currently flared. This evaluation has been performed by totaling the volume of gas currently routed to the flare that could be captured by a system with a flow capacity of 2 MMSCFD. Flow in excess of the 2 MMSCFD rated compressor capacity cannot be recovered by this system. Short duration events have instantaneous flowrates higher than the daily average, so the use of daily data overestimates the volume that the system can capture.

- A similar evaluation has been performed to determine the impact of adding 4 MMSCFD additional flare gas compressor system capacity. This would result in the capture of an additional 49 MMSCF of flared gases on an annual basis.

- Applying the average gas composition and the pounds of non-methane hydrocarbons emitted per scf of flared gas factor to the identified reduction in flared gas volumes, the estimated reduction in non-methane hydrocarbon emissions that could be achieved was estimated at 11.0 tons/year for 2 MMSCFD additional flare gas compressor capacity and 15.6 ton/year for 4 MMSCFD additional flare gas compressor capacity.

- A factor that severely limits the reduction in emissions such a recovery system would achieve in practice is the capability of the fuel gas consumers to accept these gases at the time at which they are generated (from both a volume and quality perspective). The gas storage system which has been specified for each option is necessary if the improvements in flare gas recovery shown have any chance to be realized. However, the composition of the gas could preclude its use as fuel gas and, therefore, the amount of recovered gas is likely overestimated by this analysis. In addition, the 2005 flare data indicates many days where flaring occurred on subsequent days. This would likely prevent the use of much of the recovered gas since it would have to be processed and used by the end of the day to allow accumulation of flare gas on the following day. This is unlikely and would also result in an overestimation of the flare gas actually recovered.

- In order to capture the gas associated with the type of longer duration flaring event that accounts for most emissions from the flare(s) on an annual average basis, a very large capacity for flare gas compression and storage is needed. The third case Martinez has presented, for a system with a capacity of 100 MMSCFD, reflects what would be needed to capture and control all vent gases for this type of event. The system as proposed makes use of 24 flare gas compression systems at 4 MMSCFD each feeding 97 storage spheres, each of which are 60 foot in diameter. The increase in treater capacity is limited to 8 MMSCFD, as flare gas would be stored prior to treatment and worked off through the treater at a gradual rate in line with the ability of the fuel gas system to accept it.

As noted above, any vent gases, whether resulting from an emergency or not, within flare gas recovery compressor capacity is sent to the No. 5 Gas Plant where it is scrubbed and recovered as fuel gas. If there are flare gas flows beyond the capacity of the flare gas recovery compressors, the gas cannot be compressed to the pressure required to enter the Wet gas system at the No. 5 Gas Plant. In addition, even if additional compressor capacity were available, the amount of gas that could be scrubbed and recovered as fuel gas would be limited by the amount of remaining capacity in: 1) the No. 5 Gas wet gas compressors, 2) the fuel gas scrubbing system, and 3) the fuel gas consumers.

Even if only non-emergency gas was considered, non-emergency flare gas would primarily result from planned turnaround events. This gas would tend to be high in nitrogen or hydrogen and, in general, would be relatively low in sulfur. Therefore, scrubbing this gas would not result in significant emission reductions, but would be very expensive to install and operate. Such systems were discussed above and found to not be cost effective. This analysis was done for all flaring (i.e. emergency and non-emergency). Therefore, limiting the operation of such equipment to non-emergency flaring would only make the system less cost effective.

Based on this review Martinez believes that further expansion of systems for the recovery, treatment and use of flared gases is not a cost effective approach to reducing these emissions (see Attachment 9 for cost effectiveness calculations). The major source of flared gases on a volume basis can be attributed to large flow rate 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. Martinez believes that this plan addresses such situations, as well as shorter term, smaller flaring events, and provides a cost effective method of eliminating or minimizing flaring during all situations.

Description of Prevention Measures

As noted above, the potential causes of vent gas quality or quantity issues are numerous. 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 have the potential to result in vent gas compositions or flows that would make recovery infeasible can be grouped together based on similarity of cause. These general categories, are:

- Maintenance Activities Including Startup and Shutdown
- Malfunctions and Upsets
- Emergencies
- High Base Load
- Reduced Fuel Gas Consumption
- Other Causes

Many of these causes are addressed in other sections. Maintenance related flaring is addressed in Section 3.4.1 including issues of vent gas quality and quantity. Malfunction, Upset, and Emergency related flaring is addressed in Section 3.4.3 including issues of vent gas quality and quantity. The remaining categories are addressed in this section.

High Base Load
A routinely high flow rate to the flare system can limit the additional amount of flare gas that can be sent to the flare system without flaring. Operations monitors the flow to the flare system and investigates when there are significant changes to the vent gas flow to the flares. By routinely monitoring the flow to the flare system, action can be taken early to identify the cause of the additional vent gas and, to the extent possible, take appropriate action. There are various reasons why high base flows to the flare cannot be reduced at a particular point in time. For example, if the source of the high flow to the flare is required for safety purposes such as the safe depressurization of a unit. Such situations can take several hours or longer and, during this time, Martinez would be unable to reduce the high flare flows. Another example would be if maintenance or an upset resulted in a high flare flow for a limited period of time to safely manage the gas. During that time Martinez would be unable to reduce the high flare flows. If such flows result in a reportable flare event, Martinez will conduct a causal analysis to determine whether the failure to reduce the flow was justified.

Reduced Fuel Gas Combustion
Reduced fuel gas consumption can lead to out of fuel balance situations that can cause flaring. This can be caused by energy efficiency improvements or other changes to operating processes. Martinez is committed to improving energy efficiency, while at the same time managing the fuel gas system to reduce the chance of fuel gas imbalance related flaring. As noted previously the Operations Department manages the fuel system to prevent fuel gas imbalance related flaring, to the extent feasible. Operations modifies unit operations at fuel gas generating units to reduce gas make, if needed, to address such situations.

Other Causes
If Martinez identifies any other causes that could reasonably result in vent gas composition or quantities that would make recovery infeasible, Martinez will evaluate the cause and determine whether any action is warranted to address the situation. If any additional actions are identified, Martinez will include this information in the next annual update of the flare minimization plan.

Should a situation still result in a reportable flaring event due to issues of gas quality or quantity, Martinez will conduct an analysis of the cause and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

50 Unit Flare
The 50 Unit flare was designed so that it would only be used during situations of upsets, malfunctions, or emergencies. During other situations, the 50 Unit Flare system is designed to recover any flare gas generated and send the recovered gas to the refinery fuel gas system for use in fired equipment within the refinery.

3.4.3 Malfunctions & Upsets

This section addresses situations associated with equipment failure or failure of a process to operate in a normal or usual manner. Such situations are generally referred to as "malfunctions" and "upsets". During such situations, vent gas flows to the flare system can be large due to pressure relief valves venting to the flare header or various other process streams temporarily routed to the flare to address the upset situation.

Review of Recurrent Equipment Failures or Upsets
The refinery continues to conduct recurrent failure analysis for flaring events globally. Each event is reviewed to identify the root cause. While a given Flaring Process Unit may be the cause of a flaring event, the true root cause of each event may vary. Martinez has evaluated and continues to evaluate means of minimizing flaring due to Internal Power Loss and electrical system reliability. These Prevention Measures must always be balanced with safety.

Description of prevention measures
The best way to prevent malfunctions and upsets, whether they are recurrent or not, is to take proactive actions to prevent or reduce the chance of such situations. Martinez has a number of programs in place to accomplish this. These include the Mechanical Integrity Program, Predictive and Preventive Maintenance Program, the Maintenance Training Program, and the Operations Procedures and Training Program. Each of these programs is described in more detail below. The purpose of these programs is to ensure that all reasonable efforts are taken to prevent equipment failure and to ensure that the units are maintained and operated by properly trained personnel.

Mechanical Integrity Program
The refinery's Mechanical Integrity Program addresses the integrity of process equipment and instrumentation for safe and reliable operations. The refinery maintenance program covers three types of maintenance: 1) preventative and predictive maintenance, 2) routine maintenance (repair), and 3) turnarounds. Preventative maintenance is performance of equipment inspection and repair based on time and historical knowledge of the equipment. Predictive maintenance involves utilizing technological methods of inspection to determine equipment condition. Preventative and predictive maintenance used in combination determine the inspection and repair frequency of equipment at the refinery. Routine maintenance is the repair or corrective maintenance of equipment as dictated by predictive maintenance,

preventative maintenance and equipment condition. A turnaround is maintenance of a process unit on a large scale. A turnaround is the periodic shutdown of a processing unit for cleaning, internal inspection and renewal. The process unit is opened up and its critical components are inspected and repaired during a turnaround. The goal of the Mechanical Integrity Program is to eliminate or minimize equipment failure by maintaining the equipment. This will also eliminate or minimize any releases from that equipment to the flare system.

Predictive and Preventive Maintenance Program

<u>Fixed Equipment:</u>
The Inspection Department has trained inspectors for performing inspections on fixed equipment at the refinery. Fixed equipment includes, but is not limited to equipment such as pressure relief systems, fractionators, reactors, separators, drums, strippers, tanks, exchangers, condensers, piping, etc. The Inspection Department maintains a current list of all fixed equipment, categorized by process, which includes information on the last inspection, next planned inspection and inspection frequency. Records of all equipment inspection are retained for the life of the equipment. The Inspection Department also has a written procedures manual, which contains written details on how to perform certain inspection techniques used to determine equipment serviceability. Examples of techniques used by Inspectors include: visual weld inspection, dry magnetic particle testing, wet fluorescent magnetic particle testing, liquid penetrant examination, Eddy current tube examination, IRIS tube inspection, ultrasonic testing, and radiographic viewing. The Inspection Manual also details procedures regarding how to perform an inspection for certain pieces of equipment. Examples include instructions on how to inspect piping, boilers, air receivers, pressure vessels, furnaces, and exchanger tube bundles. Inspection frequency and methods of inspection are performed according to Industry Codes and Standards and the California State (Cal-OSHA) Safety Orders. For example, pressure vessel inspection is performed according to API Standard 510 (see next paragraph for more information on API 510). The Inspection Procedures are reviewed regularly for accuracy. Any changes to Inspection Procedures are managed through a revision process for tracking changes. The Inspection Procedures Manual is available to employees both electronically through a computer shared-drive and in hard copy at their office.

API 510 inspection code provides a process to ensure that the in-service inspection, repair, alteration, and re-rating activities for pressure vessels and the pressure-relieving devices protecting these vessels are conducted properly. By following this inspection standard, the risk of an unexpected vessel failure is significantly reduced. Pressure vessels that remain in a condition of being suitable for operation reduce the likelihood of taking the vessel out of service during the unit run, which can potentially take the unit off-line. If the vessel needs to be de-pressured safely and quickly, then the potential to flare is a more likely scenario due to the sudden increase in flare header flow and pressure required which may exceed the flare recovery capacity and the flare seal system resulting in a flaring event. Keeping a pressure vessel operational in a "normal" mode reduces the potential for flaring.

<u>Rotating Equipment:</u>

The Rotating Equipment Department performs all inspections and repairs on rotating equipment at the refinery. Rotating equipment includes pumps, compressors, fans, blowers, turbines, engines, gear boxes, motors, *etc*. The rotating equipment group consists of Machinists, Machinery Field Specialists, Vibration Specialists, and Rotating Equipment Engineers. The Rotating Equipment Department maintains a current list of all rotating equipment that is categorized by type of equipment. Rotating equipment is inspected and tested using lubrication checks, oil analysis, visual inspections, vibration monitoring and testing mechanical safety devices. The frequency of these tests and inspections is based upon industry codes and standards as well as type of service. For example, steam turbines are inspected and tested according to the API Standards 611 and 612. Inspection records are maintained on file as hard copies. Vibration records are entered into a computer database for tracking. The Rotating Equipment Department also has a written procedures manual, which contains up-to-date written details on how to perform rotating equipment inspection and tests. The procedures are reviewed regularly and changes are tracked through a revision process.

Maintaining rotating equipment in good operating condition reduces the chance of malfunctions or upsets that can result in flaring. Also, preventive maintenance programs will tend to identify potential problems prior to failure and allow issues to be addressed in a planned manner. This reduces the chance of an unplanned, upset condition that can result in flaring.

<u>Instrumentation and Electrical Equipment:</u>
The Instrument and Electrical Department (I&E) performs all inspections and repairs on instrumentation and electrical equipment at the refinery. This type of equipment includes, but is not limited to, transmitters, controllers, control valves, Distributed Control Systems, analyzers, interlocks, relief valves, power distribution systems, motors, alarms, and programmable logic controllers. The I&E group consists of Electricians, Instrument Mechanics, Analyzer Mechanics and Distributed Control System Technicians. I&E maintains a current list of all electrical equipment and instrumentation. I&E has 13 programs dedicated to predictive and preventative maintenance of instrumentation and electrical equipment. The thermographic survey program is an annual performance of a survey to identify any hot spots in the power distribution system for repair. The Motor Management program addresses motor reliability. The transformer program includes inspection and testing of transformers. The UPS/Battery Program requires quarterly testing of these power sources. The Substation and Switching Station Program addresses inspection and testing of electrical power distribution stations to ensure reliability. The Insulator Washing Program covers the cleaning of high voltage insulators. The Pole Inspection Program covers annual inspection of all power poles in the refinery. The Analyzer Program covers calibration and testing of analyzers, with the results of the tests tracked by computer to predict maintenance requirements. The Vibration Program is performed on motors with the Rotating Equipment Group. The Cathodic Protection System is checked through a monthly inspection program. Control valves are serviced through a Control Valve Management Plan, where a flow-scanning system is used to quantify and record the control valve performance. The Relief Valve Servicing program covers refinery pressure relief systems. The Essential Instrument Program addresses inspection and repair of critical instrumentation. In addition, the Distributed Control System Technicians inspect and test the computer systems that control refinery processes. The test

frequencies are specified by instrumentation type and manufacturer specifications. Inspection and test records are maintained on file and tracked by database. I&E has written procedures for performing inspections and tests. These procedures are reviewed regularly and changes are tracked through a revision process. Due to the rapid technological expansion occurring in instrumentation and digital control systems, I&E has more frequent personnel training and procedure reviews than other areas.

Maintaining instrumentation and electrical equipment in good operating condition reduces the chance of malfunctions or upsets that can result in flaring. Also, preventive maintenance programs will tend to identify potential problems prior to failure and allow issues to be addressed in a planned manner. This reduces the chance of an unplanned, upset condition that can result in flaring.

Repair

Routine or corrective maintenance of equipment is performed by experienced Craftspeople. Craft specialties include Boilermakers, Welders, Pipefitters, Exchanger Shop Mechanics, Mechanics, Machinists, Riggers, Carpenters/Builders, Compressor Mechanics, Valve Mechanics, Instrument Mechanics and Electricians. Corrective maintenance is performed on equipment as dictated by predictive maintenance, preventative maintenance and equipment condition. Operator surveillance during their routine inspections of the units is also used for determining the need for repair of equipment. Documentation of repairs is developed and maintained in the applicable equipment folders for the life of the equipment. The repairs may be performed in maintenance shops or in the field. The refinery has specialized repair shops for carpenter work, welding, machine work, instrument and electrical repair, and exchanger repair. Inspectors perform inspections and tests on fixed equipment and maintenance craft personnel perform the repairs. These repairs are typically performed in the field. The Maintenance Department has written procedures for corrective maintenance of equipment. These procedures are available on the refinery intranet as well as in hard copy. Rotating equipment is both inspected and repaired by Rotating Equipment Department personnel. These repairs may be performed in a shop or in the field by Machinists or Machinery Field Specialists. The Rotating Equipment Department has written procedures for repair of the equipment. These procedures are reviewed annually and tracked through a revision process. I&E repairs electrical equipment, instrumentation and relief valves. These repairs may be performed in the shop or in the field by the appropriate Craftspeople. I&E has written procedures for repair of their equipment. These procedures are regularly reviewed and changes are tracked through a revision process.

Repair work is planned by maintenance planners. They develop detailed plans for conducting repairs in a safe manner. Depending upon the scope of work, the proper information and materials are assembled for the repair work to proceed. In addition, the appropriate safe work permit requirements are identified for the job. Upon completion, repair records for equipment specific repairs are retained in hard copy or tracked by computer database.

Equipment repairs minimize flaring by properly maintaining equipment to minimize the chance of an upset or unplanned shutdown that can result in flaring.

Turnaround

A turnaround is maintenance of a process unit on a large scale. A turnaround is the periodic shutdown of a processing unit for the cleaning, inspection and renewal of worn parts. The process unit is opened up and its critical components are inspected and repaired during a turnaround. Due to the size of the project, turnarounds take 6-24 months of planning. Three criteria determine the frequency of unit turnarounds; they are the type of unit, the history of the unit and specific government regulations. Typically, units undergo a turnaround every two to five years. Large unit turnarounds may require the use of 1000 contract craftspeople to complete the repairs.

Maintenance turnarounds minimize flaring by properly maintaining equipment to minimize the chance of an upset or unplanned shutdown that can result in flaring.

Maintenance Training Program

Staff training helps ensure that activities such as equipment inspection, problem identification, repairs and quality control of all equipment are conducted properly and that problems are identified and addressed to keep the equipment functioning properly. Properly functioning equipment reduces the likelihood of equipment malfunctions that can cause unit upsets which can result in flaring. This will also reduce the chance of having to take equipment off-line during the unit run, which can potentially lead to a flaring event.

Maintenance Craftsperson Training

The refinery employs experienced Journey-level Craftspeople in a number of disciplines to perform maintenance at the refinery. Craft disciplines include Boilermakers, Welders, Transportation (drivers), Pipefitters, Exchanger Shop Mechanics, Mechanics, Machinists, Vibration Specialists, Riggers, Carpenters/Builders, Compressor Mechanics, Valve Mechanics, Instrument Mechanics and Electricians. The refinery hires only Journey-level craftspeople. All Craftspeople must pass a written and practical exam to demonstrate their skills prior to hire. All Craftspeople are trained on the overview of the refinery processes. On a regular basis, refresher training is performed and conducted in modules. These training modules may include, but are not limited to: forklift operations, respirator fit testing, fresh air, blinding, torqueing, hose use/selection, gasket selection, fall protection, lead abatement, asbestos, lock-out/tag-out, hazardous energy, confined space, hot work, repacking valves, rebuilding site glasses, bleeder reamer use, turbine repair, laser alignment of equipment, staging/scaffolding, rigging/crane, highlift, and leak repair. During the lock-out/tag-out training module, there is an emphasis on understanding the hazardous energy sources. All Craftspeople must complete an exam at the conclusion of each training module. Vibration Specialists responsible for performing predictive and preventative maintenance on rotating equipment have been certified in their craft by attending in-depth training courses from the Vibration Institute and/or manufacturers' training courses. Machinists who perform vibration analysis on rotating equipment have received 12 hours of classroom training in addition to field training. The instrument mechanics and electricians have skills training annually, including a specialized Computer Based Training (CBT) for their craft. Under special circumstances in 1999, all refinery Maintenance Craftspeople repeated all training modules described above (with the exception of vibration training). Training records are retained.

Inspector Training

Inspectors perform inspections of structures and fixed equipment to ensure the integrity of the equipment, and thereby, the safety of personnel and property. The inspection personnel receive specialized training to assure that they are able to successfully perform their job. All Inspectors must have five years' experience in operations, welding and/or boilermaker craft. They must pass a written exam as well as a vision test. The Inspector initially is trained in a company developed training program involving in-house and off-site training. The course curriculum is focused on non-destructive testing and equipment visual inspection. Specific courses may include: Introduction to non-destructive testing, visual weld inspection, radiation safety and radiographic examination, math and physics for industrial technology, ASME pressure vessel and boiler codes, magnetic particle examination, ultrasonic examination-thickness gauging, color contact penetrant examination, API 510 on pressure vessels, API 570 on piping and API 653 on tanks. Certification of course completion is performed by written exam. All training is paid for by the refinery. The Inspector training is compliant with ASNT SNT-TC-1A and API guidelines. Recertification, as specified in ASNT SNT-TC-1A and API guidelines, occurs every 3 to 5 years depending on the method and/or certification. Inspector training is tracked by the Inspection Department by database, including when training has been completed and refresher training is due. In addition, hard copies of all Inspector certifications are kept on file. Training records are retained.

General Safety Refresher Training

In addition, all Maintenance Craftspeople and Inspectors must complete an annual CBT and classroom training that addresses chemical hazards, the emergency action plan, electrical safety awareness, safe work permitting, Personal Protective Equipment (PPE), and respiratory protection. The training records of all maintenance personnel, except Inspection, are kept by the Training department.

Quality Assurance

The quality of maintenance repair work on fixed equipment is verified by Inspectors. The Inspectors perform or oversee specific tests after the repair is complete to assure that the repair has been performed properly and with appropriate materials. The nature of the tests used for quality assurance depends upon the type of work performed and is typically specified by an Inspector. To assure the proper material has been used in building or repairing a process, the refinery has a Positive Materials Identification Procedure. This procedure involves the use of an analyzer capable of identifying metal alloys. Rotating equipment quality assurance is performed by Supervisors. They perform visual inspections, pressure testing (where and when applicable) and start-up checks. In addition, spare parts original manufacturer's number is tracked along with the manufacturer provided documentation (material certification papers) to ensure the right parts have been installed into the proper service. Instrument and Electrical repair quality is assured by strict use of original equipment manufacturer spare parts. Repair of relief valves are performed by VR qualified shops, these specialized shops have been certified by a national board to perform work on relief valves.

Quality control of repairs and maintenance helps to ensure that the repairs and/or replacements of components are correct and meet all requirements necessary for the particular job. This reduces the chance of an unplanned outage of the equipment which can cause a unit upset or shutdown which, in turn, can result in flaring.

Operations Procedures and Training Program

Operating Procedures

The refinery has written Operating Procedures for all operating units. The purpose of the Operating Procedures Program is to develop, implement and maintain operating procedures that provide clear instructions for safely conducting activities involved with refinery processes. Operating Procedures are organized into Operating Procedures Manuals for each process unit. In addition, there is an Operating Manual for each unit. Every Operating Manual contains all the process information, engineering data, and reference sources that is required to operate the unit in a safe, efficient, reliable and environmentally sound manner.

The written Operating Manuals were developed from a standard template. All Operating Manuals follow a consistent format that is divided into six sections. There is an introduction section, a process safety and environmental section, an equipment description section, a process control variable section, a troubleshooting section and a failure prevention section. In addition, both the Operating Procedures and Operating Manuals contain information so that the Operator can take appropriate action to safely perform any of the following: an initial unit start-up, normal operation of the unit, shutdown of the unit during an emergency, operation of the unit during an emergency, a normal shutdown of the unit, a startup after a turn around and a startup after an emergency shutdown. The Operating Procedures Manual and Operating Manual also contain information regarding the consequences of deviating from normal operating parameters and the steps to correct deviations and avoid deviations. In addition, the Operating Procedures Manual and Operating Manual contain information about the process safety systems and how they function. Written temporary Operating Procedures are developed if needed.

The initial development of the Operating Procedures involved Operators, Unit Supervisors, Shift Supervisors, and outside Contractors, all of whom are collectively referred to as Subject Matter Coordinators (SMCs). The SMCs wrote the initial versions of the Operating Procedures. Review and certification of the Operating Procedures occurs at regular intervals. The Area Supervisor is responsible for the review and certification of their completeness and accuracy. Operators are typically consulted during this review. During the review process, revisions to the Operating Procedures may be warranted. Any revisions to the Operating Procedures are managed through Management Of Change and operators are trained on the revisions. Hard copies of Operating Procedures are kept in each control room and at the training center. In addition, electronic copies are available on the refinery intranet.

The refinery has a permitting program to address the safe work practices involving lockout/tagout, confined space entry, opening process equipment/piping and access of personnel other than operators to the process area. The refinery also addresses Hot Work by permit. The permit template was used to address safe work practices so that maintenance work would be planned and performed in a consistently safe manner. The content of the permit forms is in compliance with Cal-OSHA regulations specific to each of the areas previously mentioned. The safe work practices and policies are available on the refinery intranet for all employees. In addition, hard copies of the policies and permits are available in unit control rooms and at the Shift Superintendent's office. Safe work practice permitting is continuously audited by the Health and Safety Department and the results are posted monthly on bulletin boards refinery-wide for employees to read. The Field Safety Supervisor manages all changes to the safe work practices and permits. Employee involvement on development and maintenance of the safe work practices occurs through the Joint Health and Safety Committee. Employees are informed of changes through the weekly/monthly safety meetings, bulletin board postings, email distribution and other appropriate methods.

Eliminating or minimizing flaring is an ongoing general operating practice. However, this has not yet been included in all startup or shutdown procedures (many operating procedures do not involve flaring issues, so startup and shutdown procedures are more pertinent). At least 20% of the shutdown procedures currently include references to eliminating or reducing flaring. As the startup and shutdown procedures are revised, such references will be included.

Operating procedures reduce flaring by instructing operators to route streams to alternate locations during depressurization of equipment, by instructing them to depressure slowly, and by instructing them to notify shift supervision before conducting depressurization operations.

Operator Training

The objective of the training program is to ensure that employees involved in the operation and maintenance of processes are trained in the tasks and information necessary to safely and effectively perform their work.

An awareness of the importance of minimizing flaring may be the most effective means of actually reducing flaring. Operators who are trained how to operate their units safely and efficiently, depressure equipment according to operating procedures, and communicate with other units effectively play a vital role in the overall goal to reduce and control flaring activities. By the operator being aware of the goal to eliminate or reduce flaring, actions will be taken consistent with that goal. Effective communication between units helps to coordinate what is being sent to the flare and minimize the chance of exceeding the flare recovery system capacity. In addition, operator training reduces the chance of upsets or other unplanned events that can result in flaring.

Initial Operator Training

The new Operators begin with six weeks of classroom training. The classroom training covers safety training, reviewing safe work practices, respiratory protection, PPE, hearing conservation and hazard communication program (this program covers how to find and use MSDSs and other portions of PSI). The new operators are also trained to the First Responder Operations Level as required by the HAZWOPER regulations. This training covers defensive actions in the event of an accidental release. In addition to the HAZWOPER training, the new Operators also receive Incipient Fire Training. The curriculum also covers a general introduction to refinery processing, followed by training modules on refinery equipment, including pumps, compressors, heat exchangers, distillation towers, valves, instrumentation, furnaces, boilers, cooling towers and electrical systems.

After the classroom training is complete, new operators begin practical training in the field. They study the Operating Procedures and Operating Manuals specific to the unit on which they are assigned. They become skilled at the details of their job, including how to perform procedures. They also learn more about their specific process unit, including its process chemistry. The new operators learn the operational details covered in the six sections of the unit's Operations Manual, with particular emphasis on process control and safety systems. The process control emphasis is on critical operating limits (COL), the consequences of operating outside the COL and how to bring the unit back under control if it has deviated outside of the COL. The safety system emphasis focuses on the importance and function of the unit safety systems.

The refinery has several units with state-of-the-art computer controls. The Operators assigned to these computer-controlled units receive additional training on computer simulators. The simulators allow the operators to practice controlling the process units under a variety of events. The simulators are a dynamic training tool, they can mimic the entire process unit and show the Operator the consequences of changing variables during process operations. Some of the unit simulators also perform scenario training. The scenarios can mimic process upset conditions that would require the operator to safely shut-down the unit. The Operator can then practice how to safely restart it.

Upon completion of the initial training, operators are given a written exam and a practical exam. The written exam covers information specific to the Operations Manual in their unit. The practical exam addresses the procedures they perform and specific details of their unit. Finally, the new operator must pass the qualification process, which is similar to an oral exam, where they demonstrate the skills they have learned to be a qualified operator. This completes the operator's certification of training.

<u>Refresher Operator Training</u>

Operator refresher training is conducted every three years. It covers the procedures and operations manual of the specific unit on which the operator is assigned. As part of their refresher training, operators must pass a written exam and a practical exam in addition to the qualification process. In addition, each year all employees, including operators, complete CBT modules on many of the topics covered in the initial operator training course. Under special circumstances in 1999, all refinery operators repeated the initial operator training and were re-certified in the same manner as described previously under initial operator training.

<u>Training documentation:</u>

The Training Department maintains records on all employee training. Initial Operator training and refresher training is tracked through a database. The database is programmed with the required training curriculum for each employee. Employee training and testing is entered into the database upon its completion; this includes training on CBTs, classroom, as well as any written or verbal test results. Training records for certain courses or safety meeting attendance are kept in hard copy in a central filing system.

In spite of such extensive efforts, equipment malfunction and upset situations can still occur. Should a malfunction or upset situation occur that results in a reportable flare event, Martinez will conduct an analysis of the cause and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

3.4.4 Other Potential Flaring Events

Should a reportable flare event occur due to any other cause not already noted in this FMP, Martinez will conduct an analysis of the cause of that event and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

Flare Testing

From time to time, testing of a flare may be required to ensure that it is operating or will operate properly. Typically this is done after construction of the flare or any significant repair or maintenance to a flare. During these situations it is important to conduct a controlled test to ensure that the flare or flares will function properly. For example, if a flare tip required replacement (due to corrosion or some other cause), a test of the flare might be performed to ensure that the replacement tip would perform properly during a flaring event. Historically, such testing has rarely been required. The test is typically performed by sending fuel gas to the flare. Typical flow rates during the test are about 5- 10 MMSCFD and the typical time to conduct a test is about 15 minutes at a time. Martinez will provide a test protocol to the BAAQMD for approval prior to conducting any flare tests.

Delayed Coker Flare Prevention Measures

As a part of the design of the Delayed Coker Revisions, prevention measures were included in the design and operation to minimize or eliminate flaring. These measures ensure that all normal operations and maintenance venting is routed to the wet gas system instead of the flare system. Therefore, there is no impact of routine operation and maintenance flare gas flow from the Delayed Coker on the refinery flare gas recovery. This is described in more detail below.

In the delayed coker, coke is produced in four large coke drums. The coker feed, vacuum residuum, are fed to the coke heaters from the fractionator. The coker heaters heat the feed to approximately 950° F. The bottom of the fractionator serves as a surge tank for the coke heater charge pumps. The heated feed is sent to two of the coke drums. Upon entering the lower pressure of a coke drum, the cracked hydrocarbons flashes and passes overhead, is quenched with heavy coker gas oil, and then enters the bottom of the fractionator. The finely divided carbon particles formed in the cracking of the large chain hydrocarbons remain in the coke drum, coalesce and form solid coke particles. These particles solidify in a matrix and build up in the drum, filling it to a predetermined level.

Two drums are online filling with coke while the other two are offline either having the coke removed from the drum or being prepared to be switched back to online. A filled coke drum is stripped of residual vapors with steam, and then quenched with water. The vapors produced by quenching are routed to the new quench tower closed blowdown system to remove coke particles and oil droplets prior to being condensed in air-cooled condensers. The remaining vapors are routed to the existing wet gas compressors at No. 5 GP and used for fuel gas and products (propane and butane).

The use of the quench tower closed blowdown system allows for the recovery of hydrocarbon from the coke drums prior to switching them off line and removing or cutting the coke. This design was developed so that the vapors would not need to be sent to the flare. In addition, the operating procedures for the delayed coker startups and shutdowns do not require flaring during the startup of the unit. Any hydrocarbons generated during startup or shutdown are recovered in the wet gas compressors at No. 5 GP. In addition, venting associated with maintenance operations will also be sent to the wet gas system and will not be sent to the flare system. The flare system only receives vent gases associated with an upset or breakdown situation. Martinez has also tied the Coker Flare into the existing flare system, and the associated recovery compressors, to recover any small leaks or minor process upsets that may occur to avoid flaring for these events. Lastly, the other general prevention measures also apply to the Coker Unit.

The Coker Modification Project included various connections to the flare header, through a flare knockout vessel. These include hydrocarbon relief valves (safety control and manual) and various hydrocarbon drains used to hydrocarbon free the equipment prior to maintenance. More specifically, there are Coke drum relief valves, Fractionator relief valves, fuel gas relief valves, Blowdown Quench System relief valves, and Strainer relief valves. There is also a valve to route Settling Drum Off Gas to the flare system (which is normally closed with the off gas normally sent to the No. 5 GP) and a natural gas purge to ensure the flare header is free of oxygen (which is recovered by Flare Recovery Compressors).

In addition, there are various pump vents/drains, heater tube vents/drains, and strainer drains that are routed to the flare header. There are also connections to cross connect the various flare headers. The 42" flare header is designed for a maximum rate of 266 MMSCFD.

The Coker Modification Project relief valves are routed to a flare knockout vessel and the gas is routed to the refinery flare system. The Coker Flare is required to ensure that, during all relief events, there is adequate flare capacity.

The Coker Flare is operated as a part of the existing, staged main refinery flare system. Additional details on the seal pot levels and header system are provided in Section 3.1.1 of the FMP and the main flare simplified flow diagram.

The operation of the Coker Flare is consistent with flare minimization. The addition of the Coker Flare to the refinery main flare system retains the overall flare minimization of the flare system as a whole. There is no routine flow to the flare system from the Delayed Coker and all the existing flare minimization efforts, including the flare gas recovery system, will continue.

The Coker Modification Project directionally reduced the chance of a fuel gas imbalance situation, which reduced the chance of flaring. The Delayed Coker produces less fuel gas than the historic Fluid Coker. In addition, the two furnaces at the Delayed Coker use a combination of fuel gas and natural gas, which increased fuel gas use. (The Fluid Coker combusted coke for heat whereas the Delayed Coker uses fuel gas/natural gas for heat.) Therefore, since less fuel gas is produced and there is more fuel gas used in the refinery, the chance of a fuel gas imbalance situation is reduced (i.e. a situation where there is temporarily more fuel gas being produced than fuel gas being consumed).

The Delayed Coker generates fuel gas continuously. However, when switching a drum, the amount of gas make reduces to about 75% of the previous amount (since the drum being switched into is not quite as hot as the drum that had been online previously). Therefore, additional natural gas needs to be added for about 2 hours after a drum switch. This serves to further reduce the chance of a fuel gas imbalance situation that could result in flaring.

50 Unit Flare Prevention Measures
As a part of the design of the 50 Unit Flare, prevention measures were included in the design and operation to minimize or eliminate flaring. These measures ensure that all normal operations and maintenance venting is routed to the fuel gas system instead of the 50 Unit Flare. Therefore, there should be no flaring associated with routine operation and maintenance at the 50 Unit. This is described in more detail below.

The 50 Unit Flare was installed as a part of a project to replace the 50 Unit Atmospheric Blowdown Tower. Various maintenance streams and pressure relief valves had been routed to the atmospheric blowdown tower. This project removed the existing atmospheric blowdown tower and replaced that system with the 50 Unit Flare and flare gas recovery system.

The 50 Unit flare gas recovery system includes a flare gas header and compressors to recover flare gas generated and send it to the refinery wet gas system where it is treated and used as fuel gas. The 50 Unit flare gas recovery system has been designed to handle scheduled routine maintenance, as well as scheduled major turnaround maintenance. The system includes a small compressor to handle the day-to day small maintenance and purge streams that may be generated. In addition, the existing spare 50 Unit wet gas compressor has been lined up and used for recovery of the vapors during de-pressuring and equipment steam-out of large process equipment during and outside of the turnarounds when non-condensable hydrocarbon loading is relatively high in the 50 Unit flare gas recovery system header. The existing spare wet gas compressor will also serve as a common spare between the flare gas recovery service and the wet gas service. Since equipment de-pressuring and steam-out operations are well planned operations, sufficient time is available for changing over from the small flare gas recovery system compressor to the existing wet gas compressor and vice versa. The existing spare wet gas compressor is expected to be used for the flare gas recovery service only for short periods of time during the beginning of the steam-out operation, when non-condensable hydrocarbons are present in relatively large quantities. Control valves have been provided on the steam-out lines from large process equipment for controlling steam-out rates to minimize the chance of the 50 Unit flare liquid seal being broken during the steam-out operations. A spill-back control valve has also been added to the design to help keep the wet gas compressor suction pressure, when in flare gas recovery service, at a constant pressure lower than the normal flare gas recovery system pressure.

In addition, a steam condenser has been added to the system design. This condenser allows the steam sent to the flare recovery system during maintenance steam out situations to be condensed, reducing the overall flow rate to the flare gas recovery system.

Small Flare Events

Martinez reviewed small flaring events from 7/1/15 through 6/30/16 that, due to the total volume or low emissions, did not reach the trigger levels for a flare causal analysis. An analysis of the average emissions associated with these five small flare events was conducted. Days with flare events that triggered a flare causal analysis and days of no flaring were excluded from this review. The average flare emissions per small flare event day were 19 lb/day of methane, 76lb/day of non-methane hydrocarbon, and 107 lb/day of SOx. One of the small flare events was related to issues with the refinery fuel gas mixpot seeing increased wet gas production, which releases the excess gas to the flare header under pressure control. Other incidents were related to general unit shutdowns and startups.

Nonetheless, a review of the causes for such events was conducted by interviewing key Operations personnel in each of the operating areas to identify situations that they recalled leading to small flare events. Planned and completed actions to eliminate or reduce flaring from small flaring situations have been noted in Attachment 16.

3.4.5 Summary

Martinez believes that the prevention measures described in this FMP are the most effective in minimizing flaring from the refinery. No other measures were considered to reduce flaring, beyond what is contained in this FMP.

Work practices to reduce flaring are written in procedures. In addition, Martinez has developed a procedure to consider flaring impacts and potential mitigations during more routine maintenance efforts. Martinez has modified the past maintenance project planning process to evaluate whether certain maintenance activity could reasonably result in flaring and, if so, consider what actions might be taken to reduce or eliminate the flaring. As noted above, should significant flaring (i.e. flaring over 500,000 scf/day) still occur, a causal analysis will be performed to determine whether there are reasonable methods to reduce or eliminate such flaring in the future. There are no other new or revised procedures planned for implementation to reduce flaring.

As noted in Section 3.4.3, Description of planned prevention measures, during the pre-planning process for planned major maintenance reducing process flow rates to eliminate or reduce flaring will be considered. Since every planned major maintenance activity is unique (i.e. the equipment being shut down, units being shut down, and other operating parameters at the time of the shutdowns), Martinez believes that this method will be the most effective in identifying methods to eliminate or reduce flaring. As noted in Section 3.4.2, many of the gas quality or quantity issues are related to planned major maintenance activities. The remaining causes of gas quality or quantity issues are: 1) malfunction, upset, or emergency (as described in Regulation 12-12-201) situations, 2) high base load situations, 3) reduced fuel gas consumption situations, and 4) possible other causes. During malfunctions, upsets, or emergency situations, reducing process flow rates to eliminate or reduce flaring will be considered when the situation is stable and any issues of safety have been addressed. High base load situations would not normally result from unit rate issues. However, if in the specific situation reducing process flow rates has the potential to eliminate or reduce flaring, it will be considered at that time. During situations when the fuel gas system is out of balance, reducing process flow rates to eliminate or reduce flaring will be considered (when the situation is stable, since these situations can occur during malfunction, upset, or emergency situations). Lastly, if any other cause is identified that results in flare gas quality or quantity issues, as a part of the evaluation noted in Section 3.4.4, reducing process flow rates to eliminate or reduce flaring will be considered.

4.0 Capital and Operating Cost

In order to allow estimation of total installed capital cost for additional flare gas compressor capacity, a series of cost curves for each of the necessary components of the system have been developed. This section defines the design of the "model" systems used to develop cost data and then presents the data.

4.1 Operation of Flare Gas Systems with Incorporation of Storage

The systems that ENSR developed pricing for are shown in the attached sketches. The sketches show a very much generalized flare gas recovery system and do not represent the actual configuration at any refinery. A typical flare gas recovery system is shown in Attachment 10. Operation of these systems is envisioned as follows:

Both existing and new flare gas compressors (exclusive of any spare units) would operate continuously. During normal operation the volume of gas they are capable of drawing from the flare gas header would be greater than the volume available, so a portion of the discharge volume would be recycled to the suction side of the compressors via a pressure control loop. Inter-stage cooling would prevent the temperature rise from exceeding design limits. Normally the volume of gas from the flare gas header and other process sources would be less than the total needed for process heaters and boilers. Natural gas would be used to make up the shortfall.

<u>System with Gas Holder</u>
At normal flow rates, pressure in the flare gas header is set by the suction-side pressure control system for the flare gas compressors as described above. When the flow of flare gas exceeds the volume that can be handled by the flare gas compressors, treaters and fuel gas system, the pressure in the flare gas header increases. This increase in pressure is sufficient to begin to lift the "piston" in the gas holder, effectively storing any excess flow that the recovery system cannot handle. Once the gas holder fills completely, if flare gas flow rates continue to be in excess of what the recovery system can handle, the pressure in the header will continue to rise until it exceeds the pressure corresponding to the depth of the flare seal, allowing any excess gas to be flared. As the

flow of gas to the flare gas header decreases, first flaring will cease, then as the pressure in the header continues to fall, gas will flow from the gas holder to the suction side of the flare gas compressors, until the gas holder has been emptied. This system is shown in the figure titled "Flare Gas Recovery with Gas Holder" (see Attachment 11).

System with Storage Sphere

If the volume of gas supplied to the fuel gas header were to exceed fuel requirements at the heaters, pressure would rise in the fuel gas header and gas would be diverted from the flare gas compressor outlet to the storage sphere. This system is shown in the figure titled "Flare Gas Recovery with Storage Sphere" (see Attachment 12). If the pressure in the sphere were to reach the compressor discharge pressure, it would stop filling, and the situation would be equivalent to that which exists with the current system when flare gas compressor capacity exceeds demand.

Gas would be returned from the sphere to the flare gas header based on header pressure. The flare gas compressors are configured to control inlet pressure at a point below where the flare seal would be broken. The storage sphere would have a pressure control system that would allow gas to flow from the sphere to the flare gas header when the header pressure was at or below a set point slightly higher than the flare gas compressor suction-side set point. This would have the effect of keeping the flare gas compressors loaded at their rated capacity whenever there is excess flare gas in the sphere to work off. When the flow of flare gas to the flare gas header exceeds the volume that can be accommodated by the treaters, process heaters and boilers, the pressure in the flare gas header would rise and flow from the sphere to the header would be stopped by the control system.

4.2 Flare Gas Storage System Options Total Installed Cost Estimation

A series of curves showing total installed cost (TIC) for installation of additional flare gas recovery capacity are presented in this section. They were developed primarily using cost data compiled from projects completed at U.S. refineries and shared with WSPA. This information was supplemented using current quotations from equipment vendors. Please note that steel costs have been escalating quickly and are continuing to increase. Therefore, the steel costs used in this analysis are likely understated. In addition, a significant amount of construction cost data used for this analysis was for construction outside of California. The cost of construction in California, and particularly the Bay Area, is significantly higher than in other regions of the country. Therefore, the construction costs used in this analysis are likely understated, as well.

Vessel Costs

Cost estimating curves (see Attachment 13) were developed for three flare gas storage options. The curves are based on gas storage in: a 40-psig spherical tank, a 120-psig spherical tank, or a conventional gas holder.

The spherical tank costs were based on quotes from CB&I for a 60-ft diameter tank, at operating pressures of 40 psig and 120 psig. A 60-ft diameter tank was used as it is near the largest economical size for a spherical tank. Estimated total installed costs include stress relief, foundations, erection, and painting. In developing the cost curves, storage volumes greater than the 60-ft diameter tank can provide are achieved by using multiple tanks. Therefore, cost data points for storage volumes greater than that for a 60-ft diameter tank were calculated based on multiplying the number of tanks by the cost for a single tank. For storage volumes less than that of a 60-ft tank, the 6/10ths rule was used to calculate the cost for that volume. The 6/10ths rule takes the original cost, multiplied by the ratio of the smaller capacity to the larger capacity to the 0.6 power ($(C_a/C_b)^{0.6}$). In general this rule is valid within +/- 75% of the original capacity.

The cost for the waste gas holder was developed based on design utilizing a 100-ft diameter tank, with a minimum height of 38 ft. and a maximum height of 60 ft. The difference between the minimum and maximum heights accommodates the surge volume of the tank. The tank cost was based on 1-inch thick carbon steel walls. The weight of steel needed was calculated, and the cost of rolled carbon steel per ton was used to calculate the raw cost of materials. Installation, painting and foundation costs were factored from the cost for the basic tank to allow development of a total installed cost. The method for calculating the cost for larger capacities and smaller capacities is identical to the method that was used for the spherical tanks.

Compressor Costs

The flare gas compressor cost curve (see Attachment 14) was developed from eight data points provided by the WSPA membership. The data points used for total installed cost were based on a flare gas compression system with a reciprocating compressor, with the exception of two systems which used a liquid ring compressor system. Costs shown are the total installed cost including all coolers, knockout pots, instrumentation and piping needed for a complete, functioning system. Where an installation consisted of multiple small compressors, the total installed cost was divided by the number of compressors to allow calculation of cost as a function of compressor size. Cost information from previous years was adjusted to a 1st quarter 2006 basis using the CE Plant Cost Index. A logarithmic trend line was used to summarize the data in a cost curve.

Gas Treatment Costs

The gas treatment system cost curve (see Attachment 15) was developed based on five data points, fit to a logarithmic trend line. In some cases it was necessary to separate out the cost for the treater portion of a project where total installed costs for several project elements were reported as a lumped value. Total installed costs for system capacities less than 8 MMSCFD are representative of system debottlenecking projects.

4.3 Flare Gas Storage System Operating Costs

A spreadsheet (see Attachment 9) has been developed for estimation of the operating costs resulting from the addition of additional flare gas recovery capacity. The spreadsheet is based on the BAAQMD cost-effectiveness guidelines for BACT using the "levelized cash flow method". Cost effectiveness is calculated as the annualized cost of the abatement system ($/yr) divided by the reduction in annual pollutant emissions (ton/yr). The spreadsheet has been populated with information based on the hypothetical installation of the 2 MMSCFD flare gas recovery system described in Section 3.4.2 above.

Attachment 1

Wet Gas, Fuel Gas, and Flare Gas Recovery System Descriptions

Vent Gas Recovery Systems - Overview

There are three systems to recover vent gas streams. They are the Wet Gas system, the Flare system, and the Vapor Recovery system. The Wet Gas system can handle gas streams that are above a pressure of about 10 psig. Lower pressure gas streams are typically sent to the Flare system since there is inadequate pressure to get into the Wet Gas system. The Vapor Recovery system recovers vapors from cone roof tanks, marine loading, and a few other very low pressure streams. Wet Gas typically is routed to the No. 5 Gas Plant where it is combined with the No. 5 Gas Plant produced gas, treated to remove H2S, and sent to the Fuel Gas system. If the No. 5 Gas Plant is down, the wet gas streams can be sent to the No.4 Gas Plant. However, the capacity of the No. 4 Gas Plant to handle these wet gas streams is lower than that at No. 5 Gas Plant. A block flow diagram of the relationship between the Wet Gas, Flare Gas, Vapor Recovery and Fuel Gas systems is provided in Figure 1.

Wet Gas System

Wet gas is comprised of off-gasses from various units that are usable as fuel gas. The wet gas system provides an alternate destination for gasses, which would otherwise be sent to flare. The refinery wet gas system consists of 4 major pipelines which connect the suppliers of wet gas such as the FCC and the crude units to the #5 Gas Plant. Typically, that is when No. 5 Gas Plant is in operation, the No. 5 Gas Plant collects the wet gas streams in the refinery, compresses those gases, separates out heavier gasses like propane and butane, and treats the remainder to remove H2S. This treated gas is then sent to the Fuel Gas system. When the No. 5 Gas Plant is shut down, the refinery wet gas streams are diverted to the No. 4 Gas Plant, where similar processing takes place. As noted above, the No. 4 Gas Plant has a lower capacity to handle these wet gas streams than the No. 5 Gas Plant.

Flare Gas System

The 24 inch diameter, 42 inch diameter, and two 48 diameter flare headers collect low pressure gases and send them to the flare area. At the flare area, a recycle compressor draws flare gas from the flare headers, compresses the flare gas, and sends it to the No. 5 Gas Plant for recovery as wet gas.

The primary reduction in flare gas comes from the flare recovery compressors directing gasses from the flare headers into the wet gas system where they are converted to fuel gas as described above. Additionally, when some equipment/units are taken out of service, they can be depressured to the wet gas system instead the flare system, if the pressure is high enough to get into the wet gas system.

There are several limitations associated with this process. The flare recovery compressors can only compress about 5 MMSCFD. If the flow to the flare headers is more than 5 MMSCFD, the excess gas will be directed to the flares. Also, if the wet gas system is already at maximum capacity, the flare recovery compressors will be limited to avoid over-pressurization problems at the No. 5 Gas Plant (excess gas going to the No. 5 Gas Plant are directed to flare, so it would just result in a recycle loop). Additionally, if the refinery is producing more fuel gas than it is consuming, the flare gas recovery will be ineffective since the flare gas will further increase the amount of fuel gas that will then be sent to the flare as the fuel gas pressure exceeds its set point. In such cases, the refinery will typically cut rate/severity at the FCC or rate at the Coker to restore balance to the fuel or wet gas systems.

Vapor Recovery System
The vapor recovery system is comprised of pipelines which route very low pressure streams to the No. 1 Gas Plant where the gas is compressed and routed to the 40 psig fuel gas system. Tank vents from cone roof tanks and the vapors recovered by the Marine Vapor Recovery system are the primary sources of gas to this system. Various other low pressure streams that are piped to the vapor recovery system can also be routed to this system.

Fuel Gas System
The Fuel Gas system includes gases produced in the No. 5 Gas Plant and No. 4 Gas Plant, as well as recovered vapors from the Wet Gas system and recovered Flare Gas. It also includes gases recovered from the Vapor Recovery system which includes tank vapors and vapors from the Marine Vapor Recovery system. In addition, No. 1 Hydrogen Plant off-gasses are sent to the fuel gas system (see Figure 1). Purchased natural gas is added to the Fuel Gas system to make up for any shortage between the fuel gas produced and consumed, maintaining pressure control in the system. Lastly, propane or butane can be added to the Fuel Gas system, if needed, to increase the BTU content of the fuel gas. Fuel Gas system production and consumption rates are provided in the section below.

The fuel gas is sent to the refinery furnaces and boilers, the Foster Wheeler Cogeneration facility, the No. 2 Hydrogen Plant, the Chemical Plant (i.e. Sulfur Plant, Ammonia Recovery Unit, and Sulfuric Acid Plant), and the DuPont Clean Technologies/MECS Inc. catalyst facility to provide a source of energy to support the various processes.

There are no specific fuel gas quality specifications, but there are general levels we attempt to meet for various parameters. For example, we attempt to meet a BTU content of about 1000 BTU/scf and maintain an oxygen level below 1%. We do not have any targets for molecular weight or specific gravity. We also do not have any alarms on the molecular weight of the flare gas. In addition, we do not have a specific target for nitrogen levels, but try to minimize the amount of nitrogen introduced into the fuel gas. Lastly, there are no hydrogen content specifications for fuel gas. However, the No. 5 Gas Plant operators monitor the operation of the wet gas compressors (e.g. the flow and RPMs). If the operation of the wet gas compressors begins to become erratic, they limit the flare gas recovery flow to maintain wet gas compressor operational stability.

Wet Gas and Fuel Gas Production and Consumption Rates

Typically, the refinery producers will generate 70-90 MMSCFD of wet gas. After being processed at the No. 5 Gas Plant, where butane and propane is recovered, about 40-60 MMSCFD of fuel gas is produced. This gas is mixed with 5-10 MMSCFD of fuel gas from the No. 4 Gas Plant, 1-5 MMSCFD from the vapor recovery system, and 0-6 MMSCFD of hydrogen bleed from #1 Hydrogen plant. These streams are supplemented with natural gas purchased from PG&E which averages around 5 MMSCFD to balance the supply of fuel gas with the demand.

There is limited flexibility to increase refinery consumption of fuel gas. This can be done via three methods. First, by switching electric drivers of rotating equipment to steam drivers (turbines), extra steam demand can be generated, allowing the boiler firing rates to be increased. However, there isn't normally a lot of room to increase consumption in this manner. Second, the amount of steam imported from Foster Wheeler can be minimized, which will increase the boiler firing rates. Lastly, it is occasionally possible to export more fuel gas to Foster Wheeler if their operating conditions allow them to receive it (e.g. if they can accept more fuel gas and still meet their permit limits). Foster Wheeler often receives between 0-10 MMSCFD of gas.

Attachment 2

Manufacturer's Recommended Compressor Repair & Maintenance

Section 3
TROUBLESHOOTING

3-1 Locating Troubles

Nash vacuum pumps and compressors require little attention other than checking the ability of the unit to obtain full volume or maintain constant vacuum. If a V-belt drive is used, V-belt tension should be checked periodically and the V-belt should be inspected for excessive wear. V-belts are normally rated for service lives of 24,000 hours. If operating difficulties arise, make the following checks:

a. Check for proper seal water flow rate as specified in Paragraph 2-2.

b. Check for the correct direction of the pump shaft rotation as cast on the body of the pump.

c. Check that the unit operates at the correct rpm-not necessarily the test rpm stamped on the pump name plates. (Refer to Paragraph 2-5, step g.)

d. Check for a restriction in the gas inlet line.

e. If the pump is shut down because of a change in temperature, noise/vibration from normal operating conditions, check bearing lubrication, bearing condition, and coupling or V-belt drive alignment. Refer to Bulletin No. 642, Installation Instructions, Nash Vacuum Pumps and Compressors, for alignment procedures and V-belt tensioning.

Note

If the trouble is not located through these checks, **call your Nash Representative** before dismantling or dissembling the pump. He will assist in locating and correcting the trouble.

Section 4
PREVENTIVE MAINTENANCE

4-1 Periodic Maintenance

Note

The following schedules should be modified as necessary for your specific operating conditions.

4-2 Six-Month Intervals

a. If the drive coupling is lubricated, it should be filled with oil or grease in accordance with the coupling manufacturer's guide.

b. Check the pump bearings and lubricate as specified in Paragraph 4-4.

c. Relubricate the drive motor bearings according to the motor manufacturer's instructions.

4-3 Twelve-Month Intervals

a. Inspect the pump bearings and lubricate as specified in Paragraph 4-4.

b. Replace the stuffing box packing as specified in Paragraph 4-5.

4-4 Bearing Lubrication

Bearings are lubricated before shipment and require no lubrication for approximately six months. To check condition and quantity of grease in the bearing bracket proceed as follows:

Note

Lubricate the bearings every year, unless the pump is being operated in a corrosive atmosphere or with a liquid compressant other than water, in which case the interval should be shortened. Lubrication should be done while the pump is running.

a. Check condition of grease in bearing caps for contamination or presence of water.

b. If grease is contaminated, remove fixed or floating bearing bracket (109 or 108), fixed or floating bearing (120 or 119) and associated parts as specified in Paragraph 5-2, steps a thru r for fixed bearing (120), or Paragraph 5-3, steps a thru l for floating bearing (119). Discard bearing.

c. Flush bearing bracket and bearing cap to remove all grease.

d. Install bearing bracket, bearing and associated parts as specified in Paragraph 5-17 and as follows:

   1. For floating bearing (119), perform steps a, c, and d, Paragraph 5-17, and steps b thru m, in Paragraph 5-18. Use associated parts.

Note

Make certain that new lip seal (5-1) is seated in floating bearing outer cap (115) with sealing lip away from bearing.

2. Install new lip seal (5-1) and secure floating bearing outer cap (115) and new gasket (115-3) to floating bearing bracket (108) as specified in Paragraph 5-20, steps m thru p.

3. Rotate shaft (111) by hand and make sure there is no rubbing or metal-to-metal contact.

4. For fixed bearing (120), perform steps a, c, and d, Paragraph 5-17; and steps a thru n, Paragraph 5-18.

CAUTION

THICKNESS OF SHIMS (4) EQUAL TO THICKNESS OF SHIMS REMOVED FROM PUMP MUST BE REINSTALLED TO MAINTAIN REQUIRED END TRAVEL.

5. Install shims (4) and fixed bearing outer cap (117) on fixed bearing bracket (109) as specified in Paragraph 5-20, steps j and k.

6. Rotate shaft by hand and make sure there is no rubbing or metal-to-metal contact.

4-5 Stuffing Box Packing

A preventive maintenance schedule should be established for the tightening and replacement of the packing in the stuffing boxes of the pump. The packing in the stuffing boxes in pumps used in continuous process systems should be replaced at annual shutdown. More frequent replacement may be required on severe process applications in which liquid compressant in the pump is contaminated by foreign material. (The packing material consists of four rings with the dimensions listed in Table 5-1.)

When replacing the packing in a stuffing box, remove the old packing as follows:

Note

Record position and number of packing rings on each side of lantern gland. This information is used to make certain that lantern gland is correctly aligned.

a. Slide slinger (3) against bearing inner cap (116 or 118).

b. Loosen and remove gland nuts (101-1 or 102-1, Figure 4-3) from studs.

Table 4-1. General Grease Specifications

GENERAL REQUIREMENTS:

A. *Premium quality* industrial bearing grease.

B. *Consistency grade:* NLGI #2

C. *Oil viscosity (minimum):*
- @ 100o (38oC) - 500 SSU (100 cSt)
- @ 210o (99oC) - 58 SSU (10 cSt)

D. *Thickener (Base):* Lithium, Lithium Complex or Polyurea for optimum WATER RESISTANCE.

E. *Performance characteristics at operating temperature:*
1. Operating temperature range; at least 0° to 250°F (18° to 121°C)
2. "Long-Life" performance
3. Good mechanical and chemical stability.

F. *Additives — Mandatory:*
1. Oxidation inhibitors
2. Rust inhibitors

G. *Additives — Optional:*
1. Anti-wear agents
2. Corrosion inhibitors
3. Metal deactivators

H. *Additives — Objectionable:*
1. Extreme Pressure (EP)* agents
2. Molybdenum disulfide (MoS_2)
3. Tackiness agents

*Some greases exhibit EP characteristics without the use of EP additives. These EP characteristics are not objectionable.

NASH STANDARD GREASE RECOMMENDATIONS (By Manufacturer):

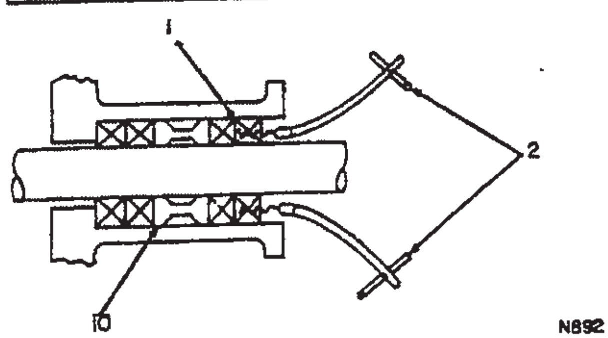
The following is a list of some greases that exhibit the desired characteristics required by Nash.

Grease Manufacturer	*Product*
AMOCO	Rykon Premium 2
Atlantic Richfield (ARCO)	ARCO Multipurpose
Chevron Oil	Chevron SRI-2
Exxon	Unirex N2
Gulf Oil	Gulfcrown No. 2
Mobil	Mobilux 2
Shell Oil	Alvania 2 or Dolium R
Texaco	Premium RB #2

*Nash Standard grease.

NOTE: This list is not an endorsement of these products and is to be used only for reference. A customer can have his local lubricant supplier cross reference these greases for an equivalent or current grease so long as it meets the General Requirements.

Grease Compatibility Note: The above listed greases are compatible with Nash Standard grease, Chevron SRI-2. To maximize a grease lubricant's performance, however, it is recommended that intermixing of different greases be kept to a minimum.



1. Packing Ring
2. Packing Pullers
10. Lantern Gland

Figure 4-1. Removing Stuffing Box Packing

Attachment 3

Main Flare System Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 3A

50 Unit Flare System Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 4

ARU Flare Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 5

Reductions Previously Realized – Causal Analyses Actions

Public Version – Confidential Information Redacted

Attachment 6

Planned Reductions Table

Public Version –
Confidential Information Redacted

Attachment 7

Causal Analyses –
Open Action Items

Public Version –
Confidential Information Redacted

Attachment 8

Main Flare Gas
Recovery System Diagram

Public Version –
Confidential Information Redacted

Attachment 9

Cost Effectiveness Calculations

Hydrocarbon Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

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

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.009324	lb non-methane hydrocarbon (POC) to flare / scf flared gas
98	% destruction of hydrocarbon in flare
0.000186	lb non-methane hydrocarbon (POC) emitted / scf flared gas
54,455	lb/yr non-methane hydrocarbon emissions prior to control
27.23	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
32,449	lb/yr non-methane hydrocarbon emissions following control
16.22	ton/yr

Reduction in Annual Pollutant Emissions =

22,006	lb/yr non-methane hydrocarbon emissions (POC)
11.00	tons/yr

Total Capital Cost $10,600,000

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	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness = $251,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton

Attorney Client Privileged Communication

Nox Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

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

Flarre gas average BTU
732 BTU/scf
0.068 lb NOx/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000498	lb NOx / scf flare gas
0	% destruction of NOx in flare
0.0000498	lb NOx emitted / scf flared gas
14,535	lb/yr NOx emissions prior to control
7.27	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
8,661	lb/yr NOx emissions following control
4.33	ton/yr

Reduction in Annual Pollutant Emissions =

5,874	lb/yr NOx emissions
2.94	tons/yr

Total Capital Cost $10,600,000

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	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System =	$2,765,000

Cost Effectiveness =	$942,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

CO Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

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

Flarre gas average BTU
732 BTU/scf
0.37 lb CO/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0002708	lb CO / scf flare gas
0	% destruction of CO in flare
0.0002708	lb CO emitted / scf flared gas
79,085	lb/yr CO emissions prior to control
39.54	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
47,126	lb/yr CO emissions following control
23.56	ton/yr

Reduction in Annual Pollutant Emissions =

31,959	lb/yr CO emissions
15.98	tons/yr

Total Capital Cost $10,600,000

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	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$173,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

PM Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

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

Flarre gas average BTU
732 BTU/scf
0.1 lb PM/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000732	lb PM / scf flare gas
0	% destruction of PM in flare
0.0000732	lb PM emitted / scf flared gas
21,374	lb/yr PM emissions prior to control
10.69	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
12,737	lb/yr PM emissions following control
6.37	ton/yr

Reduction in Annual Pollutant Emissions =

8,638	lb/yr PM emissions
4.32	tons/yr

Total Capital Cost $10,600,000

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	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$640,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

SO2 Cost/Benefit Analysis for Flare Mininimization

Year	SO2 (tons/year)
2012	48
2013	62
2014	370
2015	69
2016 YTD	22
Average for 2012 - 2015 (Baseline Emissions)	137
Control Option Emissions	27
Reduction in Emissions	110

This number is still conservatively high since there are instances that no matter how much extra flare gas compressor capacity, we would not recover the gases, such as power outages, higher flow events, and loss of 5 Gas Plant compressors or Flare Gas Recovery Compressors.

Assumes 80% reduction due to above instances

In $millions

	2006	2016
Compressor Cost Two 5.5 MMSCFD Comp	15	
Amine Treater Cost	7	
Piping	4.4	
Total Capital Cost	26.4	30.9936
2006 to 2016 Inflation (%)	17.4	

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		10	years
CRF =		0.1359	
Utilities	$/Year	363,940.00	

Annual Costs = Direct Costs + Indirect Costs

Direct Costs	$/Year	
Labor	619872	2% of capital cost
Replacement Parts	619872	2% of capital cost
Utilities	363940	(400 bhp for flare compressor, 0.85 efficiency at design, 8760 operating hours per year)
	$ 1,603,684	

Indirect Costs	
Overhead at 80% of Labor Costs	495898
Property Tax at 1% of Total Capital	309936
Insurance at 1% of Total Capital	309936
General & Admin at 2% of Total Cap	619872
Capital Recovery at CRF x Total Cap	4211037
	$ 5,946,679

Annualized Cost of Abatement System $ 7,550,363

Cost Effectiveness for SO2 = $ 68,715 per ton

based on annualized emissions and annualized cost

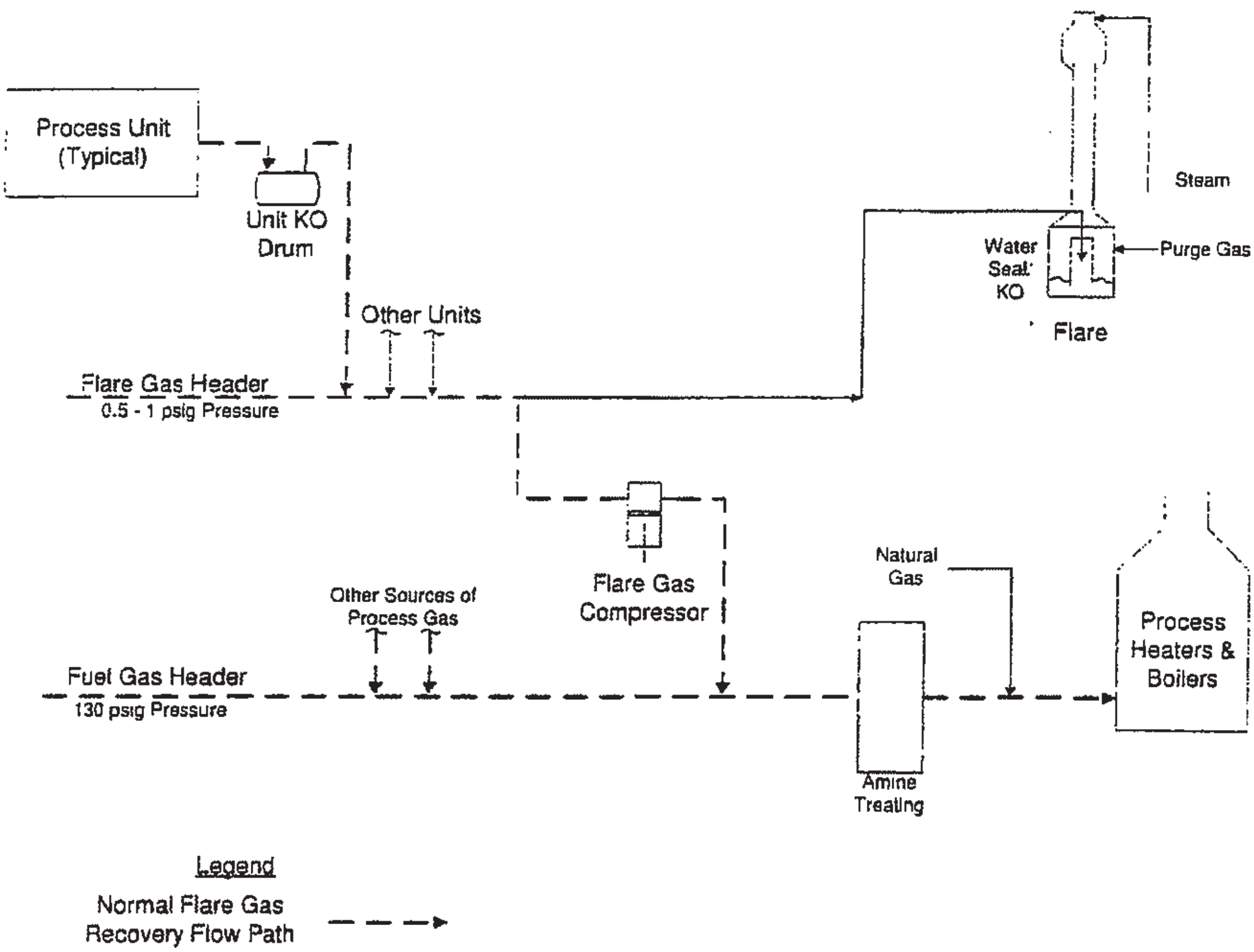
Cost Effectiveness hurdle for BACT analysis is $18,200 / ton SO2

Attorney Client Privileged Communication

Attachment 10

Typical Flare Gas Recovery System Diagram

Typical Flare Gas Recovery System

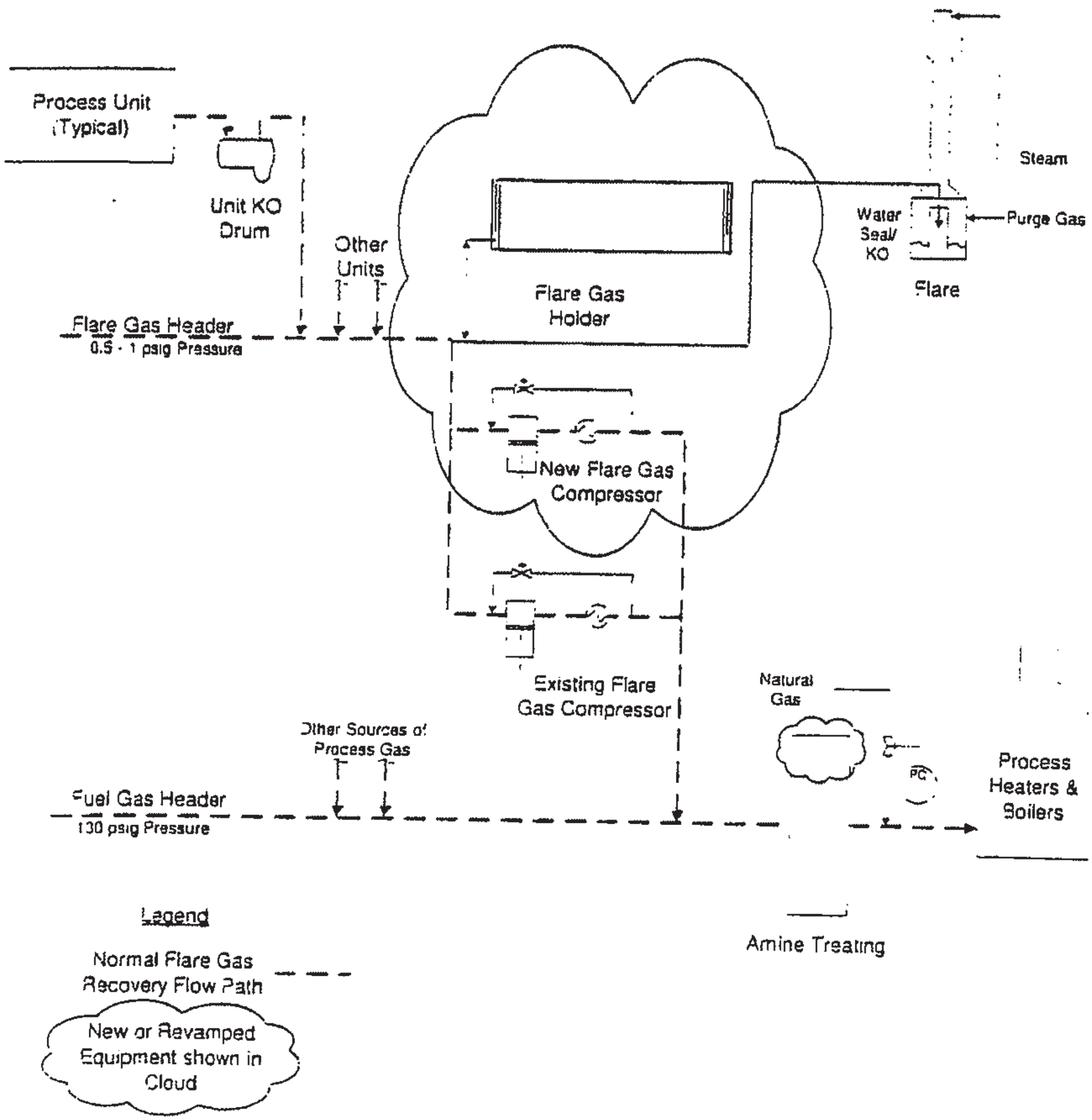


May 30, 2006

Attachment 11

Flare Gas Recovery with Gas Holder Diagram

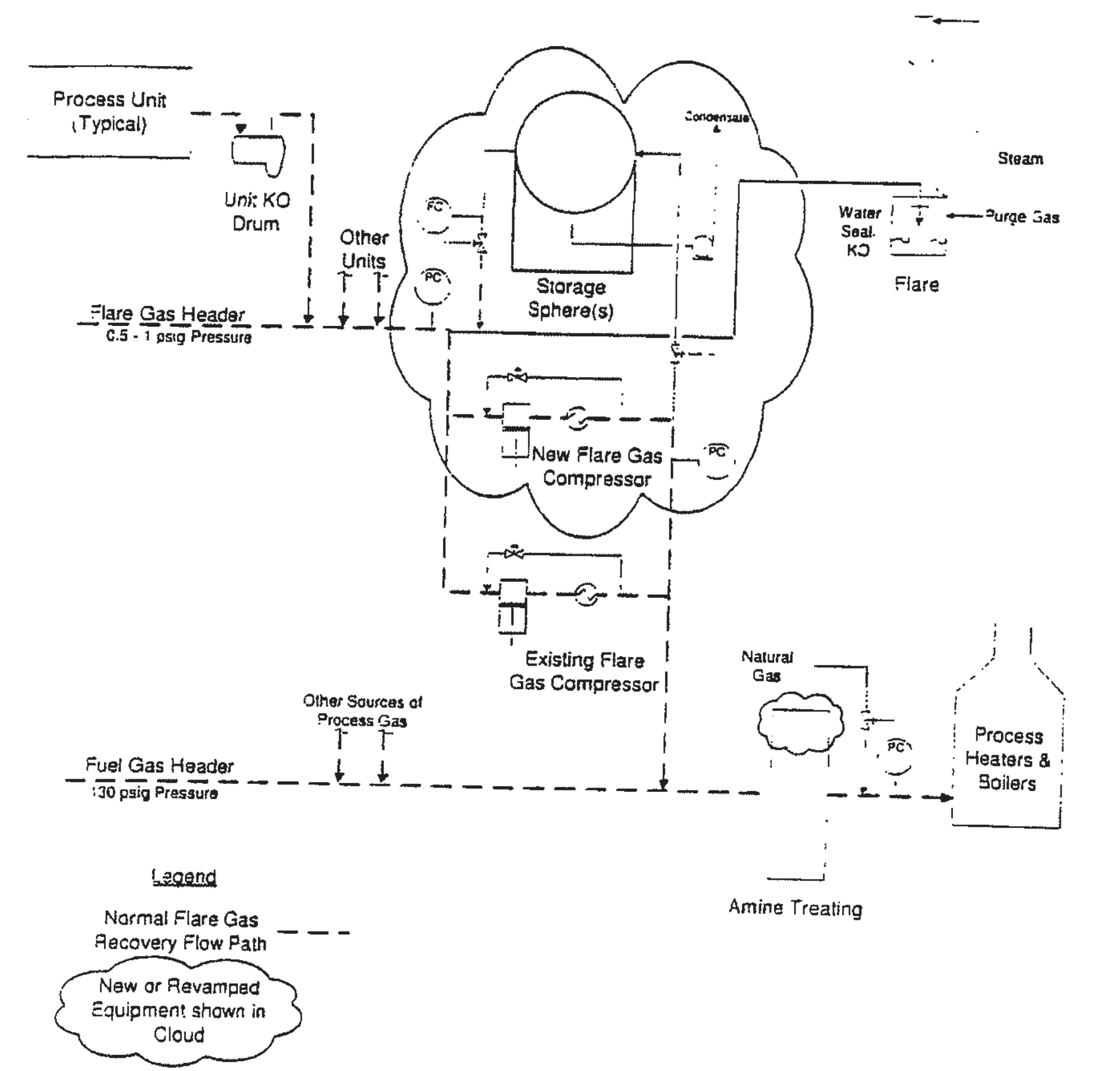
Flare Gas Recovery With Gas Holder



Attachment 12

Flare Gas Recovery with Gas Storage Diagram

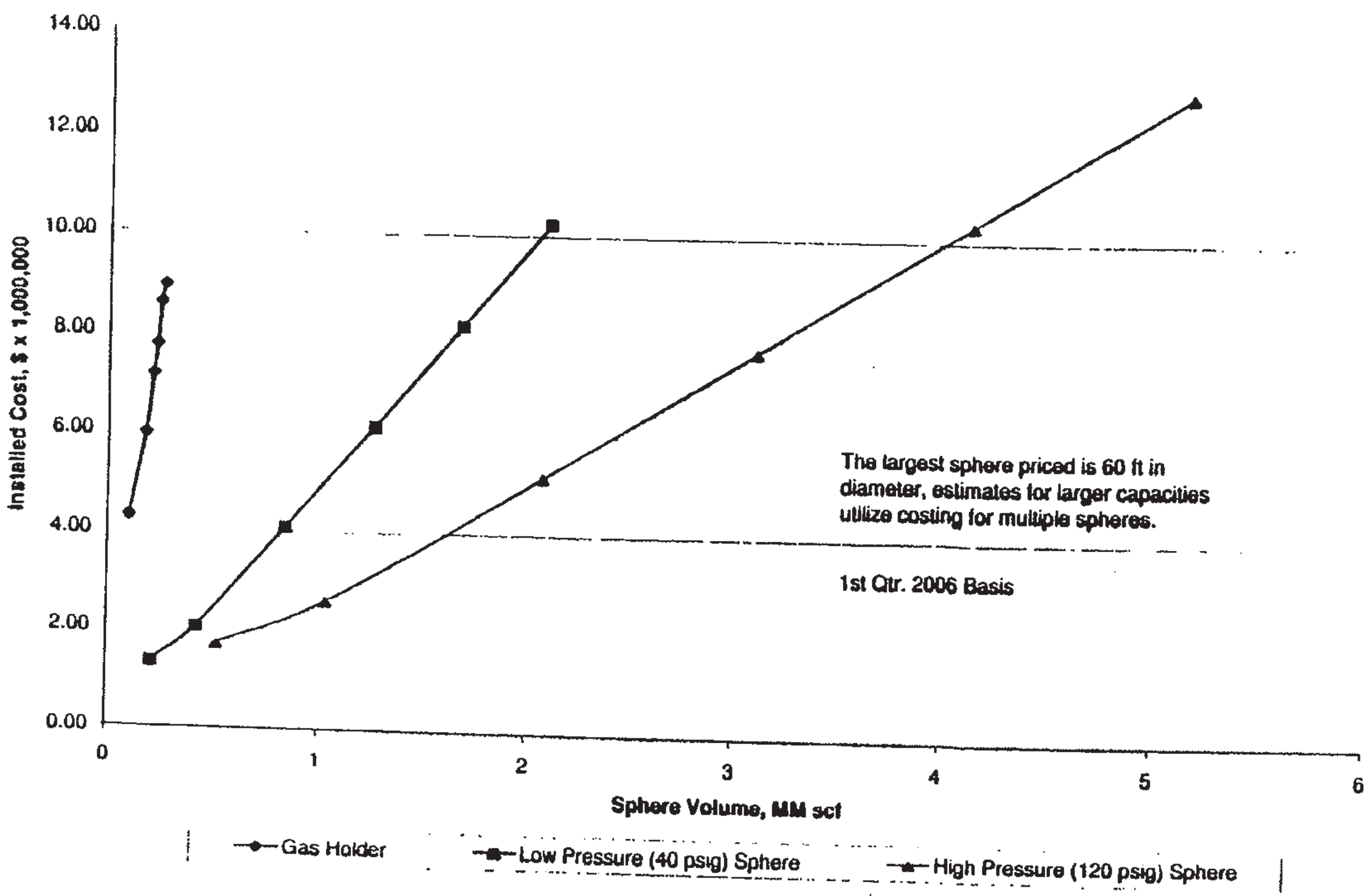
Flare Gas Recovery With Storage Sphere



Attachment 13

Vessel Cost Curve

Flare Gas Storage Options

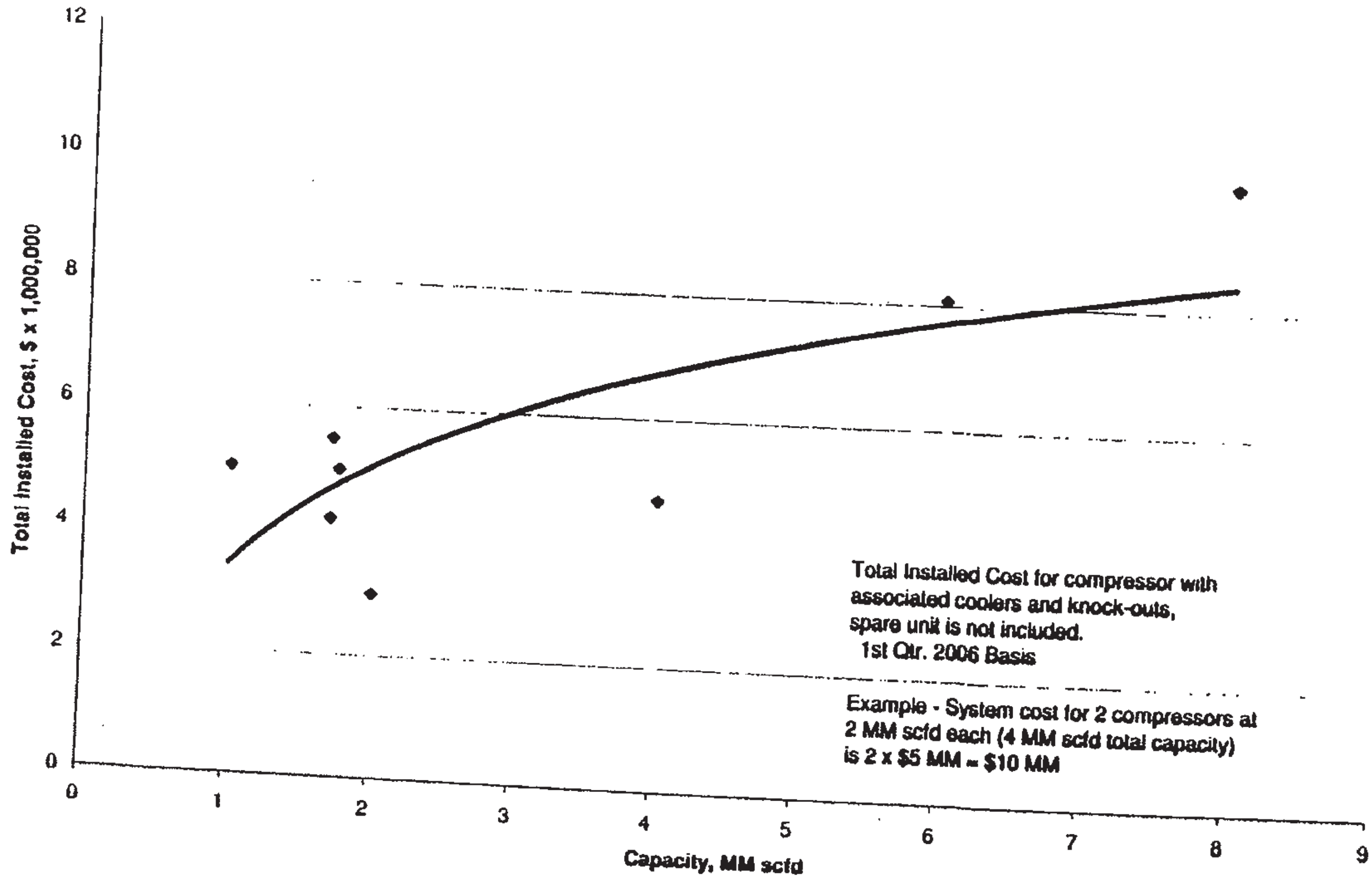


Confidential Attorney-Client Priviliged Work Document

Attachment 14

Compressor Cost Curve

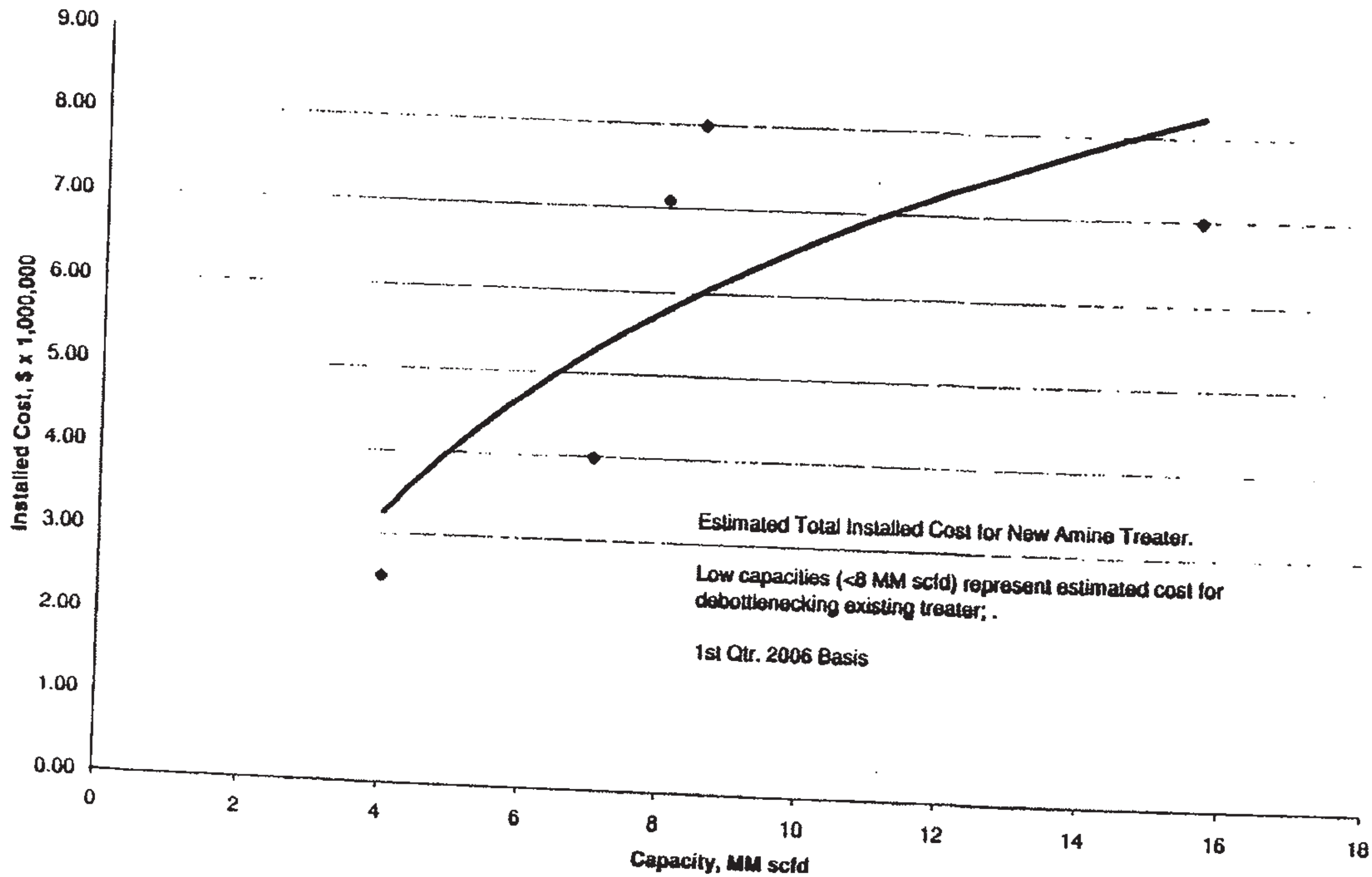
Flare Gas Compressor System Costs



Attachment 15

Gas Treatment Cost Curve

Fuel Gas Amine Treater Costs



Attachment 16

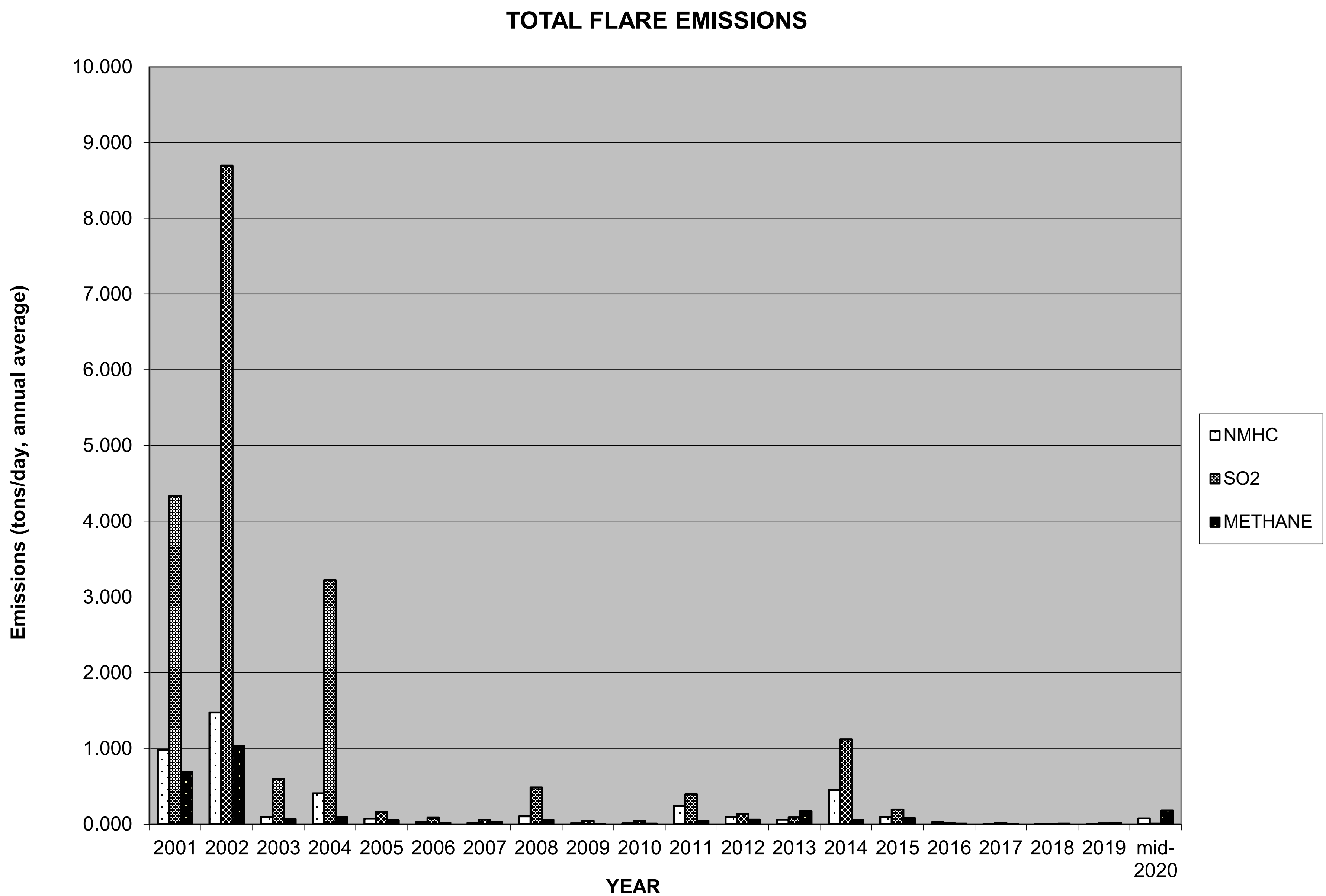
Small Flare Events
Action List

Public Version
Confidential Information Redacted

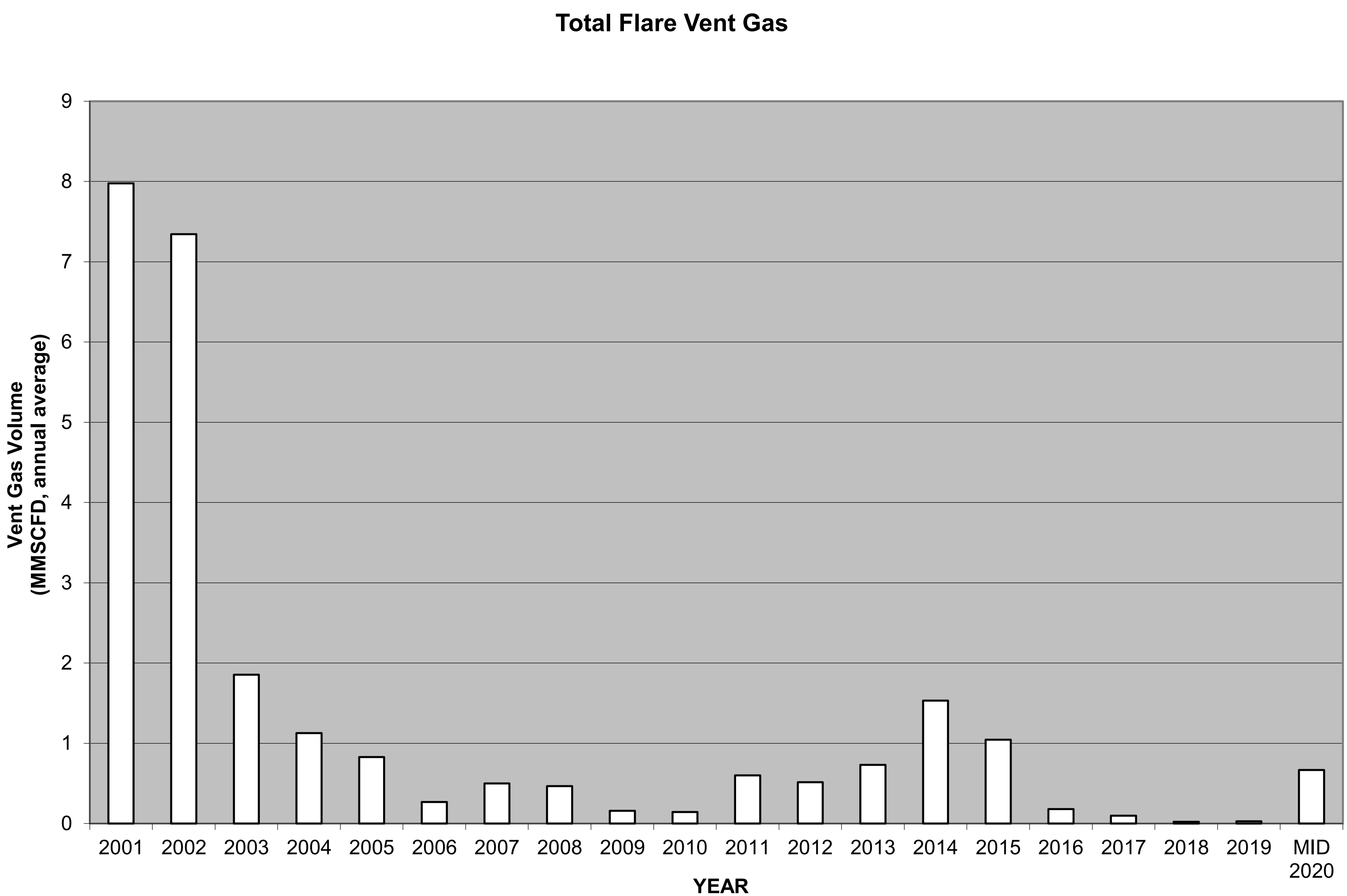
Attachment 17

Executive Summary Graphs

Marathon's Tesoro Martinez Refinery
Flare Minimization Plan - 2020 Update



Marathon's Tesoro Martinez Refinery
Flare Minimization Plan - 2020 Update



Martinez Refinery Renewable Fuels Project

(County File CDLP20-02046)

CONTRA COSTA COUNTY DEPARTMENT OF CONSERVATION AND DEVELOPMENT

JOSEPH W. LAWLOR JR, AICP, PROJECT PLANNER

CONTACT: JOSEPH.LAWLOR@DCD.CCCOUNTY.US, 925-655-2872

Today's Presentation

PROJECT BACKGROUND

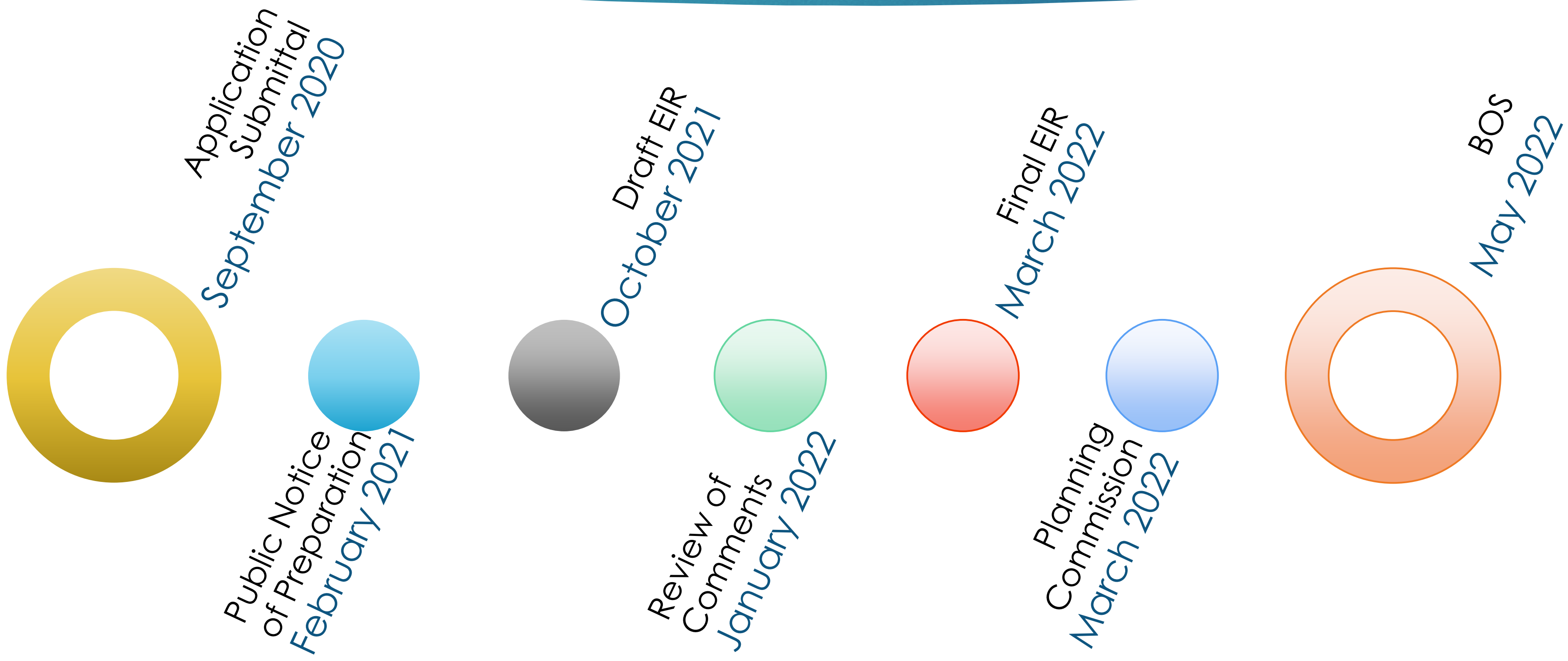
PROJECT OVERVIEW

ENVIRONMENTAL IMPACT REPORT

APPEAL OVERVIEW

Background

Review Timeline



Submittal

MARATHON

Tesoro Refining & Marketing Company LLC, an indirect, wholly owned subsidiary of Marathon Petroleum Corporation ("Marathon")

Applied for a Land Use Permit on September 16, 2020

Notice of Preparation

The County Distributed a CEQA Notice of Preparation of an Environmental Impact Report on February 17, 2021.

The County held a Public Scoping Meeting on March 15, 2021.

Draft Environmental Impact Report

Preparation of the DEIR from February through October 2021 (9 Months)

Draft EIR was Released on October 18, 2021 For a 60-Day Public Review

Comment Review for FEIR

From December 2021 to March 2022 Individual Comments Were Reviewed and Responded To

Final EIR and Planning Commission

The Final EIR, including the response to all comments, was completed and presented to the Planning Commission for Certification on March 23, 2022

Final EIR and Planning Commission

After the close of the hearing, the Planning Commission voted 6-0 to certify the Project environmental impact report and approve the land use permit application

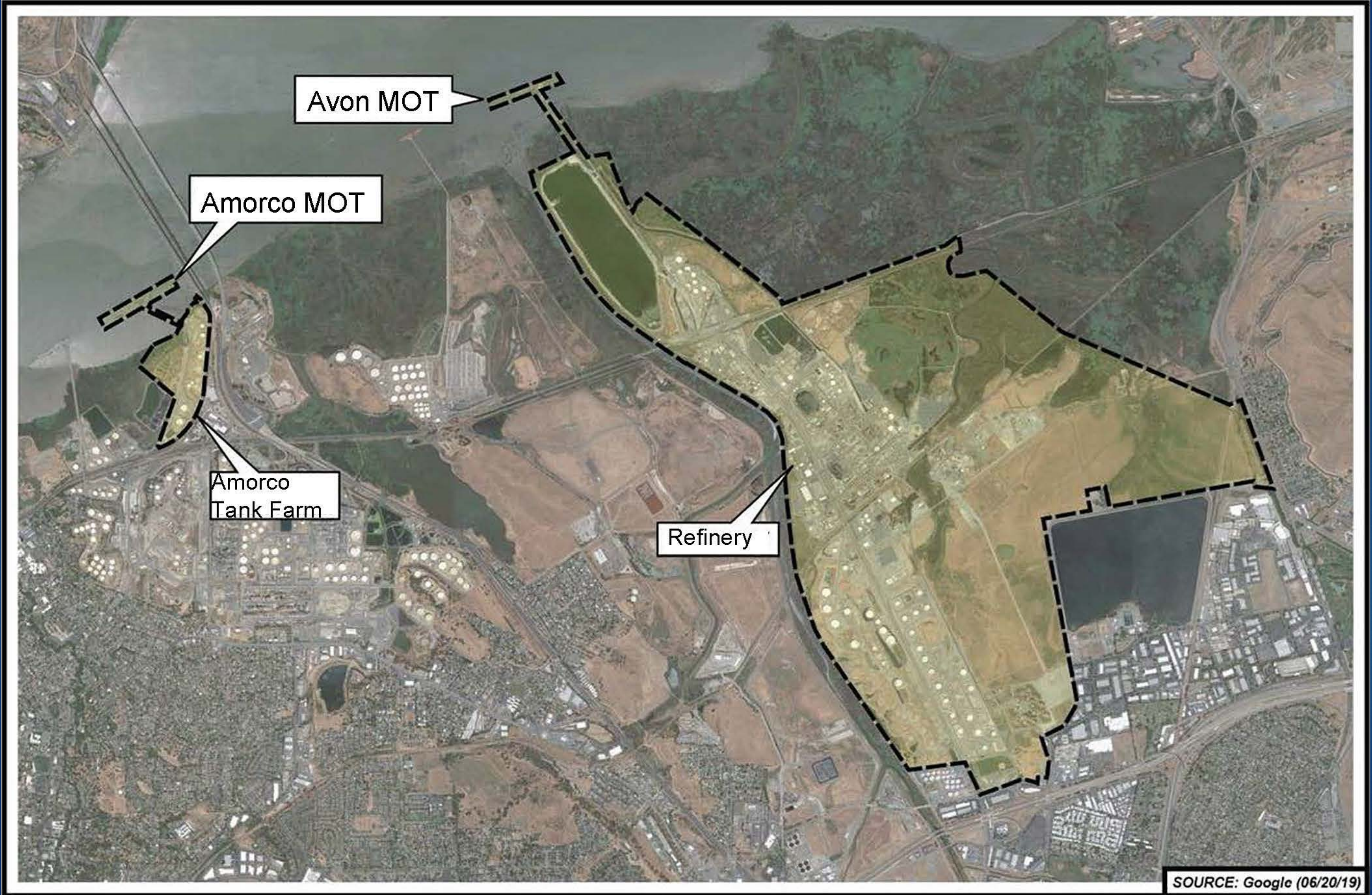
Final EIR and Planning Commission

An appeal of the Planning Commission's decision was submitted on March 28, 2022

Project Overview

Project Site

Location	150 Solano Way, Pacheco, CA
Site	2,000-acre site 1,130 Acres Developed Refining Operations 870 Acres Undeveloped Marshlands and Grasslands
General Plan and Zoning	Heavy Industry (HI), Water (WA), and Open Space (OS) Heavy Industrial District (H-I), Light Industrial District (L-I), and Railroad Corridor (-X) Combining District


Avon MOT
Amorco MOT
Amorco Tank Farm
Refinery
SOURCE: Google (06/20/19)

Martinez Refinery Renewable Fuels Project

Modifications and repurposing of the existing refinery facility to production of fuels from renewable sources including rendered fats, soybean and corn oil and other cooking or vegetable oils.

Proposed Modifications

Avon Marine Terminal

- Pipes and Hoses Reconfigured to Separate Petroleum and Renewable feedstocks

- Pipelines heated and insulated to transmit renewable feedstock

Proposed Modifications

Amorco Marine Terminal

- Modified Fender to Allow Smaller Vessels
- Maintenance and Repairs to Concrete and Five Pilings
- Changed from Receiving to Distributing

Proposed Modifications

Pipelines

- Added Insulation Heat Tracing to Ensure Product Stays Fluid

Proposed Modifications

Utilities

- New Pretreatment Unit and Stage 1 Wastewater Treatment Unit

Proposed Modifications

Phase 1 Refining Unit Modifications

- No. 3 Hydrodesulfurization Unit Revamp

- Hydrocracker 2nd Stage Unit Revamp

- No. 5 Gas Plant Revamp

Proposed Modifications

Refining Unit Modifications Cont.

- New Thermal Oxidizer for Sour Water Stripper

- Hydrocracker 1st Stage Unit

- No. 2 Hydrodesulfurization Unit

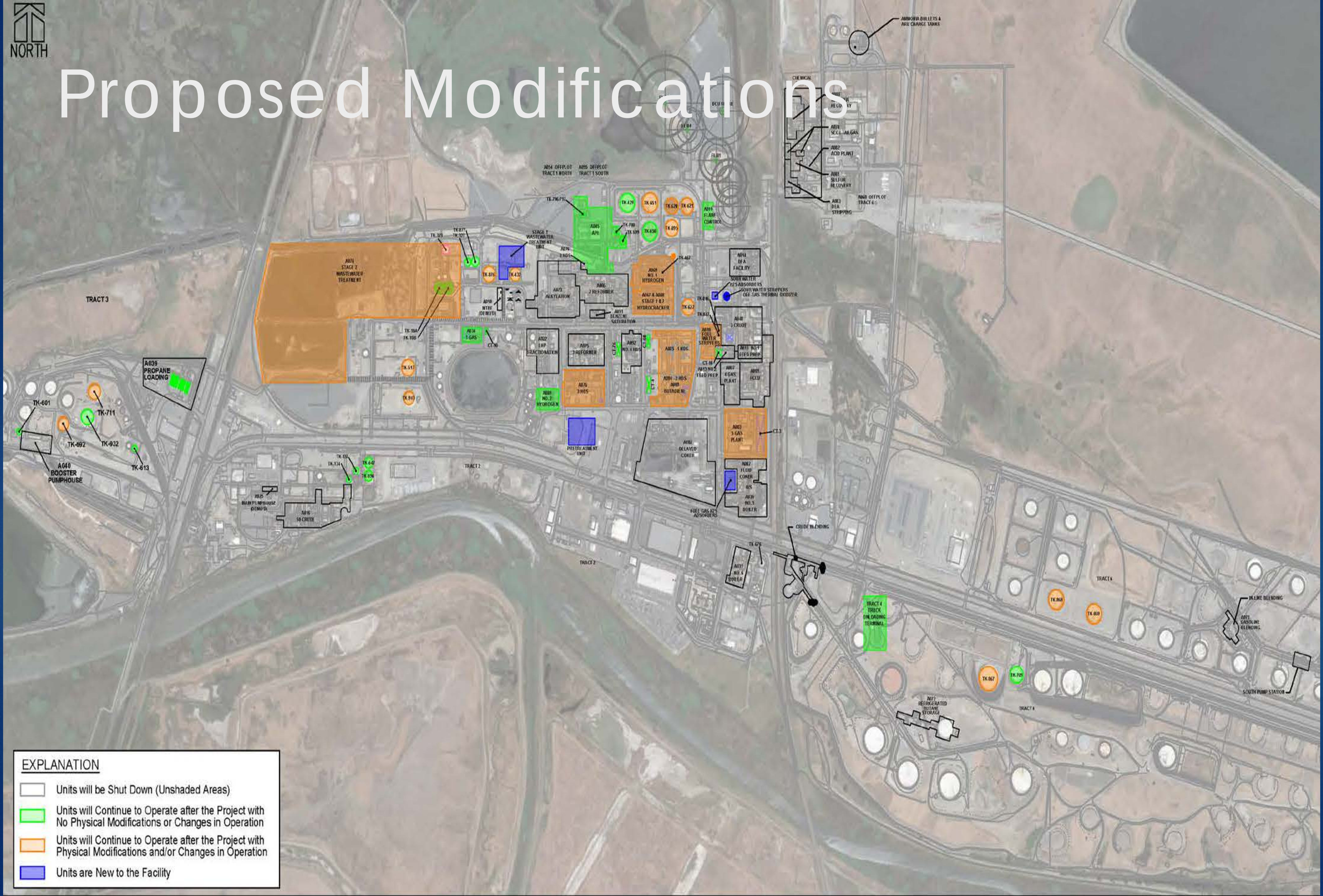
Proposed Modifications

Tanks

- Up to 29 Tanks Repurposed for Project

- 15 of the 29 Tanks Upgraded for Renewable Feedstocks

Proposed Modifications



Project Operations

Feedstock Throughput

- Previously161,000 bpd Petroleum Feedstocks
- 23,000 bpd Renewable Feedstocks (Phase 1)
- 48,000 bpd Renewable Feedstocks (Phase 2)

Project Operations

Transportation by Truck, Rail, Vessel and Pipeline

	Pre-Project		Post-Project
Truck:	205 Daily	→	180 Daily
Railcars:	13 Daily	→	63 Daily
Vessels:	3 Weekly	→	7 Weekly

Project Operations

Emissions Change Criteria Pollutants

Criteria Pollutants Daily Emissions Change lbs./day Pre- to Post-Project

Source	NOx		SO2		CO		POC		PM10		PM2.5	
On-Site Stationary Sources	-1783.52	-27.93%	-1390.40	-30.90%	-3354.26	-48.34%	-6944.86	-66.44%	-1212.46	-70.15%	-1173.07	-74.79%
Employee Vehicles	-1.94	-0.03%	-0.11	0.00%	-17.74	-0.26%	-0.48	0.00%	-10.70	-0.62%	-1.71	-0.11%
Trucks	5.10	0.08%	0.07	0.00%	-4.73	-0.07%	-0.26	0.00%	-0.03	0.00%	0.09	0.01%
Rail	-2.03	-0.03%	0.00	0.00%	-0.64	-0.01%	-0.06	0.00%	-0.05	0.00%	-0.04	0.00%
Vessels	-1,342.55	-21.03%	-2,197.27	-48.83%	-25.33	-0.37%	-83.48	-0.80%	-150.15	-8.69%	-55.80	-3.56%
Off-Site Stationary Sources	52.94	0.83%	16.90	0.38%	10.57	0.15%	4.28	0.04%	1.81	0.10%	1.81	0.12%
Total	-3,072.00	-48%	-3,570.82	-79%	-3,392.12	-49%	-7,024.85	-67%	-1,371.58	-79%	-1,228.73	-78%

Project Operations

Emissions Change Criteria Pollutants

Criteria Pollutants Daily Emissions Change lbs./day Pre- to Post-Project

Source	NOx		SO2		CO		POC		PM10		PM2.5	
On-Site Stationary Sources	-1783.52	-27.93%	-1390.40	-30.90%	-3354.26	-48.34%	-6944.86	-66.44%	-1212.46	-70.15%	-1173.07	-74.79%
Employee Vehicles	-1.94	-0.03%	-0.11	0.00%	-17.74	-0.26%	-0.48	0.00%	-10.70	-0.62%	-1.71	-0.11%
Trucks	5.10	0.08%	0.07	0.00%	-4.73	-0.07%	-0.26	0.00%	-0.03	0.00%	0.09	0.01%
Rail	-2.03	-0.03%	0.00	0.00%	-0.64	-0.01%	-0.06	0.00%	-0.05	0.00%	-0.04	0.00%
Vessels	-1,342.55	-21.03%	-2,197.27	-48.83%	-25.33	-0.37%	-83.48	-0.80%	-150.15	-8.69%	-55.80	-3.56%
Off-Site Stationary Sources	52.94	0.83%	16.90	0.38%	10.57	0.15%	4.28	0.04%	1.81	0.10%	1.81	0.12%
Total	-3,072.00	-48%	-3,570.82	-79%	-3,392.12	-49%	-7,024.85	-67%	-1,371.58	-79%	-1,228.73	-78%

Project Operations

Emission Change Greenhouse Gases

GHG Emission Change MT/Year Pre- to Post-Project

Source	CO_2 (MT)		CH_4 (MT)		N_2O (MT)		Total CO_2e	
On-Site Stationary Sources	**-1178230**	**-61.11%**	**-56.78**	**-62.94%**	**-9.45**	**-57.23%**	**-1182352**	**-61.10%**
Employee Vehicles	-1,387	**-0.07%**	-0.01	**-0.01%**	-0.13	**-0.79%**	-1,427	**-0.07%**
Trucks	8,852	**0.46%**	0.01	**0.01%**	1.39	**8.42%**	9,285	**0.48%**
Rail	3,402	**0.18%**	0.27	**0.30%**	0.08	**0.48%**	3,434	**0.18%**
Vessels	-21,233	**-1.10%**	-0.25	**-0.28%**	-1.46	**-8.84%**	-21,692	**-1.12%**
Off-Site Stationary Sources	**303918**	**15.76%**	**2.43**	**2.69%**	**0.24**	**1.45%**	**304044**	**15.71%**
Total	**-884,677**	**-46%**	**-54.33**	**-60%**	**-9.32**	**-56%**	**-888,707**	**-46%**

Project Operations

Emission Change Greenhouse Gases

GHG Emission Change MT/Year Pre- to Post-Project

Source	CO_2 (MT)		CH_4 (MT)		N_2O (MT)		Total CO_2e	
On-Site Stationary Sources	**-1178230**	**-61.11%**	**-56.78**	**-62.94%**	**-9.45**	**-57.23%**	**-1182352**	**-61.10%**
Employee Vehicles	-1,387	**-0.07%**	-0.01	**-0.01%**	-0.13	**-0.79%**	-1,427	**-0.07%**
Trucks	8,852	**0.46%**	0.01	**0.01%**	1.39	**8.42%**	9,285	**0.48%**
Rail	3,402	**0.18%**	0.27	**0.30%**	0.08	**0.48%**	3,434	**0.18%**
Vessels	-21,233	**-1.10%**	-0.25	**-0.28%**	-1.46	**-8.84%**	-21,692	**-1.12%**
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Total	**-884,677**	**-46%**	**-54.33**	**-60%**	**-9.32**	**-56%**	**-888,707**	**-46%**

Project Context

Low Carbon Fuel Standard (LCFS)

The LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions.

The LCFS standards are expressed in terms of the "carbon intensity" (CI) of gasoline and diesel fuel and their respective substitutes.

Project Context

CARB is currently receiving public input on potential amendments to the LCFS.

2022 Scoping Plan update will evaluate how to achieve carbon neutrality by mid-century and the types and role of low carbon fuels needed in the future.

Future rulemaking could potentially take effect in 2024 upon approval of the 2022 Scoping Plan Update in late 2022.

Environmental Impact Report

CEQA Environmental Impact Report

CEQA OVERVIEW

PROJECT DESCRIPTION

PROJECT BASELINE

IMPACTS

ALTERNATIVES

California Environmental Quality Act Overview

Preparation of an EIR:

Scoping – Solicitation of Agencies and Interested Parties

Draft EIR – Project Description, Impact Analysis, Alternatives

Comments – 60-day Comment Period for Public Review of DEIR

FEIR – Response to Comments and Necessary Revisions

Project Description – Project Objectives

Marathon Identified 6 Project Objectives

Project Description – Project Objectives

1. Repurpose the Marathon Martinez Refinery to a renewable fuels production facility.

Project Description – Project Objectives

2. Eliminate the refining of crude oil at the Martinez Refinery while creating high quality jobs.

Project Description – Project Objectives

3. Provide renewable fuels to allow California to achieve significant progress towards meeting its renewable energy goals.

Project Description – Project Objectives

4. Produce renewable fuels that significantly reduce the lifecycle generation of greenhouse gas emissions, as well as other criteria pollutants including particulate matter.

Project Description – Project Objectives

5. Reduce emissions from mobile sources by providing cleaner burning fuels.

Project Description – Project Objectives

6. Repurpose/reuse existing critical infrastructure, to the extent feasible.

Baseline

"An EIR must include a **description of the physical environmental conditions in the vicinity of the project**. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant. The description of the environmental setting shall be no longer than is necessary to provide an understanding of the significant effects of the proposed project and its alternatives. The purpose of this requirement 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"

Baseline

5-year Period for Baseline presents the variation in production at the Refinery (2016 to 2020). Captures turnaround schedule and market fluctuations.

Baseline is used for comparison in Environmental Impacts Analysis.

Primary factors for baseline selection were representativeness and conservativeness.

Baseline

Table 3-4 Comparative Vehicle and Vessel Traffic for Marathon Refinery, 1-year, 3-year Average, and 5-year Average

Vessel or Vehicle	Units	1-year (2019-2020)	1-year (2018-2019)	3-year Average (2017-2020)	5-year Average (2015-2020)
Truck	Miles Traveled	2,837,991	4,559,507	3,972,015	4,146,210
Train	Miles Traveled	2,380	4,820	4,154	4,605
Vessel	Calls	124	161	150	143

Source: Marathon Petroleum Corporation, 2021

Baseline

Table 3.3-7: Comparison of Average Annual Emissions, 1 year, 3 years and 5 years

Pollutant	Unit	1-year Average (2019-2020)	1-year Average (2018-2019)	3-year Average (2017-2019)	5-year Average (2015-2020)
NO_X	Ton	586.55	794.79	720.77	749.97
SO_2	Ton	565.68	722.03	672.12	679.66
CO	Ton	446.38	805.62	717.50	670.89
POC/ Hydrocarbons	Ton	192.62	234.93	225.74	196.69
PM_{10}	Ton	223.01	364.15	262.54	269.55
$PM_{2.5}$	Ton	201.91	338.75	229.36	242.42
CO_2	Metric Ton	1,151,267.22	2,279,796.34	1,875,119.45	1,925,745.20
N_2O	Metric Ton	10.38	18.26	15.58	16.16

Source: Marathon Petroleum Corporation, 2021

Environmental Impacts Analysis

Impact Summary – Mitigated Significant Impacts

Construction-related Air Emissions

Odor

Marine and Avian Biological Resources (non-spill related)

Cultural resources

Seismicity

Hazards

Tribal Cultural Resources

Environmental Impacts Analysis

Impact Summary – Six Significant and Unavoidable Impacts

Air Quality (2)

Biological Resources (2)

Hazards and Hazardous Materials (1)

Water Quality (1)

Alternatives

"No Project" Alternative

Compare the impacts of approving the proposed project with the impacts of not approving the proposed project.

Under the No Project scenario, the proposed Renewable Fuels Project would not proceed. Instead, Refinery operations would resume.

Alternatives

Reduced Renewable Feedstock Throughput Alternative

Conversion of the Refinery from a crude oil processing facility to a facility for the refining of renewable feedstock at a reduced capacity of 23,000 bpd maximum.

Alternatives

Green Hydrogen Alternative

"Green" hydrogen would be used in the renewable fuels refining process instead of steam methane reforming technology.

Alternatives

Environmentally Superior Alternative

The Reduced Renewable Feedstock Throughput Alternative would not result in any impacts that would be greater than the proposed Project, and in many cases would result in reduced impacts.

However, would generate fewer jobs and result in a lower volume of renewable fuels to support the State's low-carbon fuel goals, and would not achieve Project objectives as well as the proposed Project.

Appeal

Appeal Filed

Joint Appeal Filed On March 28, 2022, Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County

Major Appeal Points

The Appeal presents five general issues:

- Adequacy of Disclosure of Information and Mitigation for Significant Impacts;
- Adequacy of Response to Public Comments;
- Findings Concerning Choice of Alternatives and Throughput Volumes;
- Introduction of “New” Information; and
- Accuracy of the Statement of Overriding Considerations

Adequacy of Disclosure of Information and Mitigation for Significant Impacts

The following issues are addressed within the first appeal point:

- (a) Project description
- (b) Baseline
- (c) Operational upsets
- (d) Food system oil consumption
- (e) Odor mitigation plan
- (f) Cumulative impacts
- (g) California climate pathways
- (h) Transportation risk impacts

Adequacy of Response to Public Comments

The Appeal then presents three specific topics as inadequately addressed in FEIR:

- Process Hazards (Response I(c))
- Cumulative Impacts (Response I(e))
- California's climate paths (Response I(g))

Findings

The Appeal questions the adequacy of the findings and throughput analysis:

- Findings for Alternatives
- Project Throughput Limits

Introduction of “New” Information

Appeal states that the identification of “HEFA” is new information

Accuracy of the Statement of Overriding Considerations

Appeal states that certain impacts are inadequately addressed in the Statement of Overriding Considerations:

- Safety; and
- Land Use Issues

Staff Recommendation

1. OPEN the public hearing.

2. CERTIFY that the Environmental Impact Report (EIR).

3. CERTIFY the EIR prepared for the Martinez Refinery Renewable Fuels Project.

4. ADOPT the CEQA findings for the Project.

5. ADOPT the Mitigation Monitoring and Reporting Program for the Project.

6. ADOPT the statement of overriding considerations for the Project.

7. DIRECT the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk.

8. SPECIFY that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based.

9. DENY the appeal of NRDC et. al.

10. APPROVE the Martinez Refinery Renewable Fuels Project. (Permit No. CDLP20-02046).

11. APPROVE the findings in support of the Project.

12. APPROVE the Project conditions of approval.

13. APPROVE the attached Community Benefits Agreement.

CONCLUSION

Proposed Martinez Refinery Renewable Fuels Project:

- Is consistent with the General Plan and the Heavy Industrial zoning designation.

- Environmental impacts would be mitigated to less-than-significant levels or overriding considerations exist.

- Preserves the health, safety, and general welfare of the public.

- Benefits include providing jobs, improving air quality, reducing the amount of hazardous materials in the area, reduction in greenhouse gas emissions, and decrease energy (electricity and natural gas) demand at the facility.

Questions?

05-03-2022 D.1 and D.2

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

Letters received for Board consideration
Packet I

Pg 1	Valerie Carpenter, El Cerrito	4/29/2022 form-EIR	oppose
Pg 2	Christopher Martin, Richmond	4/29/2022 form-EIR	oppose
Pg 3	Linda Ostro, Rossmoor	4/29/2022 form-EIR	oppose
Pg 4	Michael D'Adamo, Ph.D, Kensington	4/29/2022 form-EIR	oppose
Pg 5	Bridget Wellerstein, MS. Ed., OTL, Lafayette	4/29/2022 form-EIR	oppose
Pg 6	Daniel Rodriguez	4/29/2022 form-EIR	oppose
Pg 7	Mady Martin, Richmond	4/29/2022 form-EIR	oppose
Pg 8	Lynne Oliver, Richmond	4/29/2022 form-EIR	oppose
Pg 9	Theresa Dixon, Urban Tilth, Richmond	4/29/2022 form-EIR	oppose
Pg 10	Marti Roach	4/29/2022	oppose
Pg 11	Margaret C. Murray, Pinole	4/29/2022 form-EIR	oppose
Pg 12	Sophie Van Ronsele, Richmond	4/29/2022 form-EIR	oppose
Pg 13	Peter Freedman, El Cerrito	4/29/2022	oppose
Pg 14	Emily H. Hopkins, Walnut Creek	4/29/2022 form-EIR	oppose
Pg 15	Susanna Marshland, Kensington	4/29/2022 form-EIR	oppose
Pg 16	Jean Evans, Concord	4/29/2022 form-EIR	oppose
Pg 17	Lisa Jackson	4/29/2022 form-EIR	oppose
Pg 18	Arthur Clinton, El Cerrito	4/29/2022 form-EIR	oppose
Pg 19	Michael Domagalski, Port Costa	4/29/2022 form-EIR	oppose
Pg 20	Marci Armstrong, Rodeo	4/29/2022 form-EIR	oppose

From: Firemonkey14 < net>
Sent: Friday, April 29, 2022 8:17 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Valerie Carpenter

El Cerrito, CA

From: christopher martin < :.com>
Sent: Friday, April 29, 2022 8:29 AM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs.

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Vote to reject. Thank you.

Christopher Martin

Richmond, CA. 94805

From: Linda Ostro <l
Sent: Friday, April 29, 2022 8:40 AM
To: Clerk of the Board
Subject: RE: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you!

A concerned citizen,

Linda Ostro, Rossmoor resident, Walnut Creek

From: Michael D'Adamo < n>
Sent: Friday, April 29, 2022 8:42 AM
To: Clerk of the Board
Subject: Decision on Biofuels

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

In addition, the fossil fuel industry is seeking ways to survive. While that is completely understandable, it is time to recognize that putting any GHGs in the atmosphere has to end to prevent catastrophic conditions that threaten the existence of our species.

Sincerely,

Michael D'Adamo, Ph.D.

Kensington resident

From:	Bridget Wellerstein <
Sent:	Friday, April 29, 2022 8:55 AM
To:	Clerk of the Board
Subject:	Biofuels EIR

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Bridget Wellerstein M.S. Ed., OTL

(Lafayette)

Stacey Boyd

From:	Daniel Rodriguez < ail.com>
Sent:	Friday, April 29, 2022 9:25 AM
To:	Clerk of the Board
Subject:	Reject Biofuels Projects

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

From: Mady Martin < gmail.com>
Sent: Friday, April 29, 2022 9:45 AM
To: Clerk of the Board
Subject: Protect Our Environment, reject land use permits

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Vote to reject. Thank you.

Mady M.

Resident of Richmond, CA. 94805

From: Lynne Olivier <lynneo2@comcast.net>
Sent: Friday, April 29, 2022 9:46 AM
To: Clerk of the Board
Subject: Land Use Permits

Dear Contra Costa Supervisors,

Please reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- ***Failure to consider climate impacts***
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,
Lynne Olivier
[illegible]
Richmond, CA 94805

From: theresa dixon >
Sent: Friday, April 29, 2022 10:33 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

--
THERESA DIXON
Urban Tilth
CSA Procurement Manager
323 Brookside Dr
Richmond, California 94801
303-596-1048

June McHuen

From:	Marti Roach
Sent:	Friday, April 29, 2022 10:43 AM
To:	Clerk of the Board
Cc:	martiroach@gmail.com
Subject:	May 3rd BOS Meeting: Marathon and P66 EIRS
Importance:	High
Follow Up Flag:	Follow up
Flag Status:	Completed

Dear Contra Costa Supervisors,

It is important to the community that you slow down the EIR process on the Phillips 66 and Marathon Refinery biofuels projects. Highly technical and well documented comments from multiple public interest, environmental justice and environmental groups have detailed failures in the EIR.

Remember the precautionary principle: in new projects where uncertainty over immediate and long-term impacts exist, responsible decision makers should exercise caution, and pause and review before leaping into new innovations that may prove disastrous.

Some of the failures of the EIR include:

- Not taking into account climate impacts (remember you have acknowledged we are in a climate emergency),
- Not taking into account the impacts of burning food for fuel as demand for feedstock production skyrockets,
- Risks and environmental degradation due to feedstock production,
- Risks related to safety and air air quality due to the scale of these projects and potentially increased operational accidents like flaring, explosions and gas releases.

A more rigorous assessment is needed.

Thank you all for your service to our County,

-Marti Roach

June McHuen

From:	Margaret Murray :mail.com>
Sent:	Friday, April 29, 2022 10:52 AM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs
Follow Up Flag:	Follow up
Flag Status:	Completed

Dear Contra Costa Supervisors,

I am writing to you (for my very first time after living in Concord and now in Pinole for 40 years) to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
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The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Margaret C. Murray
Pinole, CA

June McHuen

From: Sophie Van Ronselé
Sent: Friday, April 29, 2022 11:18 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Follow Up Flag: Follow up
Flag Status: Completed

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

In community,

Sophie Van Ronsele
Richmond, CA

Sophie Van Ronselé
(All Pronouns)
+1 415-216-3376

"The future of our earth may depend upon the ability of all women to identify and develop new definitions of power and new patterns of relating across difference."
- Audre Lorde

June McHuen

From: Peter Freedman
Sent: Friday, April 29, 2022 11:25 AM
To: Clerk of the Board
Subject: Biofuels

Vote "No." on BioFuels. in Contra Costa County.
Peter Freedman

El Cerrito, CA
94530

From: Emily Hopkins < m>
Sent: Friday, April 29, 2022 11:25 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Follow Up Flag: Follow up
Flag Status: Completed

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects must have a more thorough EIR.

And I believe analysis using current science on biofuels, including the social and human costs of shifting from food production to fuel production, will show that this shift is not in the immediate or long term interest of our local or global community.

Sincerely,

--
Emily H. Hopkins
Walnut Creek, CA 94598
http://www.linkedin.com/in/emily1hopkins

June McHuen

From: Susanna M < l.com>
Sent: Friday, April 29, 2022 11:30 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

--
Susanna Marshland, Kensington 94707

June McHuen

From:	Jean Evan: .com>
Sent:	Friday, April 29, 2022 11:50 AM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I am a Concord resident and I am very concerned about the environmental impact of the proposed biofuels projects. I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you,

Jean Evans, Concord, CA 94518

From:	Lisa Jackson · >
Sent:	Friday, April 29, 2022 11:57 AM
To:	Clerk of the Board
Subject:	Please Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

As a resident of unincorporated Contra Costa County, I am requesting that you reject the land use permits for Phillips 66 and Marathon Refinery biofuels projects and require an additional environmental impact review. There are serious concerns from many environmental groups on aspects of the project not addressed by the draft EIRs. There are long term consequences for the people of your county and even wider impacts for the planet, if these projects are adopted without fully addressing those concerns around safety and land use.

The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you,

Lisa Jackson.

June McHuen

From: Arthur Clinto[redacted]n>
Sent: Friday, April 29, 2022 12:54 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- Failure to provide an adequate project description
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen
- Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production
- Failure to consider climate impacts
- Failure to account for cumulative impacts
- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects **must** have a more thorough EIR.

Thank you.

Arthur Clinton, Jr.

El Cerrito

From: Michael Domagalski
Sent: Friday, April 29, 2022 1:18 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
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- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Michael Domagalski
Port Costa, CA 94569

mailed to BOS 04-29-22

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

Letters received for Board consideration

Packet 2

Pg 1	J.A. Zaitlin, Kensington	4/29/2022	form-EIR	oppose
Pg 2	Cori Pansarasa, El Cerrito	4/29/2022	form-EIR	oppose
Pg 3	Marcia Liberson, Walnut Creek	4/29/2022	form-EIR	oppose
Pg 4	Cathy Druck, Crockett	4/29/2022	form-EIR	oppose
Pg 5	Betty Lobos, Concord	4/29/2022		oppose
Pg 6	Bonnie Pannell, Crockett	4/29/2022	____	oppose
Pg 7	Jane Courant, Richmond	4/30/2022	form-EIR	oppose
Pg 8	Jackie Mann, 350 Contra Costa	4/30/2022		oppose
Pg 9	Ogie Strogatz, Walnut Creek	4/30/2022		oppose
Pg 10	Janet Pygeorge	4/30/2022		
Pg 11	Denice A. Dennis, 1000 Grandmothers for Future Generations	4/30/2022		oppose
Pg 12	Cynthia Mahoney, M.D., Climate Health Now; Medical Society Consortioum on Climate & Health; Clinical Associate Professor of Medicine, Stanford Universtiy (ret)	4/30/2022		oppose
Pg 13	Nora Privitera, Oakland	4/30/2022		oppose
Pg 14	Jennifer Russell, Walnut Creek	4/30/2022		oppose
Pg 15	Nick Ratto, City of Alameda; 350 Bay Area Action	4/30/2022	form-EIR	oppose
Pg 16	Diane Dulmage, Richmone	5/1/2022	form-EIR	oppose
Pg 17	Michael Freeman, El Cerrito	5/1/2022		oppose
Pg 18	Mike Moore, Oakley (Marathon)	5/1/2022	form-EIR	oppose
Pg 19	Mike Moore, Oakley (Phillips 66)	5/1/2022	form-EIR	oppose
Pg 20	Emily Wheeler, Walnut Creek	5/1/2022	form-EIR	oppose
Pg 21	Debi Clifford	5/1/2022		oppose
Pg 22	Jeffrey Mann, Lafayette	5/1/2022		oppose
Pg 23	Vanessa Warheit, El Cerrito, EV Charging Access for All; Emerge CA Class of '21	5/1/2022		oppose
Pg 24	Marinell Daniel, El Sobrante	5/2/2022		oppose
Pg 25	Elena Engel, San Francisco	5/2/2022		oppose
Pg 26	Helena Birecki, 350 Bay Area	05-2-022		oppose
Pg 27	Scott Bartlebaugh, Crockett Improvement Association	5/2/2022		oppose
Pg 28	Roland Saher, Live Oak	5/2/2022		oppose

From: Marcia L. .om>
Sent: Friday, April 29, 2022 4:53 PM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,
I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Marcia Liberson, Walnut Creek CA

From: cathy druck :om>
Sent: Friday, April 29, 2022 5:07 PM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

These projects *must* have a more thorough EIR.

I appreciate your attention to this matter

Catherine Druck

Crockett, California

From: Betty Lobos < .net>
Sent: Friday, April 29, 2022 6:03 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa County Supervisors,

I am concerned about the environmental impact reviews (EIRs) for the Phillips 66 and Marathon Refinery biofuels projects. Comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of those points. I urge you to reject the land use permits and to require additional EIRs.

The final EIRs inadequately meet the following expectations:

Providing an adequate, detailed project description
Accounting for safety and air pollution concerns from potential hazards such as flaring, explosions, gas releases, and increased use of hydrogen
Accounting for impacts of burning human food as "feedstock" in biofuel production
Adequately considering climate impacts
Complying with the CEQA Requirement to respond to public comments

I was proud when my county declared a Climate Emergency that commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects must have a more thorough EIR.

Sincerely,
Elizabeth (Betty) Lobos
Concord, CA

From: Bonnie Pannell <
Sent: Friday, April 29, 2022 9:41 PM
To: Clerk of the Board
Subject: Please Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I live in a "cancer belt" because of the refineries near me, such as Phillips 66. Communities such as mine are pacified with occasional public meetings sponsored by the county government with representatives giving lip service to a plan of environmental improvements, but it never happens. What we get is the status quo or something worse. Our country is on a trajectory toward severe global warming and extinction and, yet, we still give more consideration to the big polluters than we do the health of the planet. As the advice goes, "think globally, act locally." I hope you will align with that slogan in all of your deliberations.

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,
Bonnie Pannell
St.
Crockett, Ca 94525

From: Jane Courant < .com>
Sent: Saturday, April 30, 2022 6:42 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Hi Dear Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

SIncerely yours,

Jane Courant

z Avenue

Richmond 94804

From: jackie mann <[illegible]@att.net>
Sent: Saturday, April 30, 2022 8:18 AM
To: Clerk of the Board
Subject: May 3rd Appeal for on Renewable Fuels Projects for Marathon and Phillips 66

Please submit my letter to the Supervisors and for the record.
Sincerely,
Jackie Garcia Mann, 350 Contra Costa
Lafayette

Dear Supervisors, 29 April 2022

The purpose of CEQA is to create actions to mitigate environmental impacts. Likewise, these EIRs are vague, generalized and ignore many impacts which require mitigation. This is a violation of CEQA and creates legal jeopardy for the county. As the Appeals from environmental groups focus on specific failures of the EIR, **I wish to address the lack of guardrails and limits. These projects purposely have vague and open-ended descriptions, which may not reflect what is actually implemented.**

The refineries should post bonds for clean up and remediation of these hazardous refinery sites and risk bonds for accidents. **This should begin immediately, while there is leverage for this permit** (not 15 years down the road as currently proposed). If the companies fail, taxpayers will be burdened with expensive toxic cleanup sites that negatively impact community health, local economics, and property values. It is not fair to externalize these economic risks onto the communities. The externalized health impacts are bad enough.

For instance, if state policy changes and LCFCs are removed or biofuel refining is no longer economically feasible, these refineries may close with short notice. This is apparent in the recent closing of Marathon Refinery for economic reasons. They could sit "idle" for decades with little hope to reopen and no plan or financing for clean up. **Bond the cleanup/decommissioning in advance as a condition of approval**.

The land-use permits should specify exact products and maximum production amounts. There is no limit on throughputs. As currently written, the refineries can double the proposed production or switch to SAF or some other bio-product. This would have health and safety impacts NOT EVALUATED in the current EIRs. Guardrails should include production caps which apply to specific products and require a new permit for new biofuel products, SAF, or different ratios of products.

When refineries seek to produce Sustainable Aviation Fuel (SAF) as a main product, require a new land use permit and EIR review.

What are the limits on petroleum refining? As written, the Phillips 66 permit allows "temporary increase" in petroleum refining. How can EIR impacts be evaluated without specific information compared to current operations? This is an open ticket. Do current permits for petroleum refining expire? **Specify an end-date and amount.**

Community Recourse: **Pollution, noise, odors, explosions, flaring, fires, oh my!**
These things happen now and may increase with increased hydrogen cracking needed for biofuel refining. Regulatory agencies and fines have done little. Sink some teeth into this land use permit and safeguard the frontline community with **conditions of approval that retain local authority** to shutdown the refineries for violations or being a bad neighbor. **BOS, protect your people!**

From: Ogie Strogatz <[redacted]mail.com>
Sent: Saturday, April 30, 2022 8:20 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Respectfully,

Ogie Strogatz

[redacted], Walnut Creek CA 94597

Sent from my iPhone

From:	Denice A Dennis <...mph@gmail.com>
Sent:	Saturday, April 30, 2022 12:00 PM
To:	Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc:	Clerk of the Board
Subject:	Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Denice A. Dennis, MPH

1000 Grandmothers for Future Generations

From: cynthia mahoney < @comcast.net>
Sent: Saturday, April 30, 2022 1:20 PM
To: Clerk of the Board
Cc: Jackie Mann
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
    - *The surrounding community already suffers from high pollution and excessive asthma and cancer which must be addressed and mitigated.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
    - *This is especially important as we see heat and other climate disasters impacting food supplies, like the situation now in India with devastating effects on the wheat crop*
- *Failure to consider climate impacts*
    - *We have to stop burning things - not just fossil fuels, but burning and releasing carbon. We have to stop clearing land to grow things to burn - which doubly impacts the carbon cycle imbalance.*
- *Failure to account for cumulative impacts*
    - The experience with corn ethanol shows how easily a "feel good' proposal can be a boondoggle which does not actually lower total emissions.
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents.

For all these reasons, these projects *must* have a more thorough EIR.

Cynthia Mahoney MD

Climate Health Now
Advocate for the Medical Society Consortium on Climate & Health
Clinical Associate Professor of Medicine, Stanford University(ret.)

From:	Nora Privitera ....cast.net>
Sent:	Saturday, April 30, 2022 4:14 PM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
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- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Nora Privitera
Oakland, CA

From:	Jennifer Russell <
Sent:	Saturday, April 30, 2022 4:16 PM
To:	Clerk of the Board
Subject:	Letter to Supervisors

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
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- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Yours Truly,

Jennifer Russell

Walnut Creek CA 94595

From: ratto:
Sent: Saturday, April 30, 2022 6:58 PM
To: Clerk of the Board
Subject: Contra Costa Supervisors - Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews (EIRs) for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's [Declaration of Climate Emergency] commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,
Nick
Nick Ratto
Legislative Lead - Transportation
City of Alameda
350BayArea ACTION

From: Diane D <
Sent: Sunday, May 1, 2022 11:19 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIR

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR

Diane Dulmage

Richmond 94804

Dilicious50@gmail.com

From: M 064 Freeman <
Sent: Sunday, May 1, 2022 12:46 PM
To: Clerk of the Board
Subject: [BULK] Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

Biofuels are not clean energy!

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- *Failure to Comply with the CEQA Requirement to Respond to Public Comments*

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you,

Michael Freeman
El Cerrito, CA

From: Mike Moore < ,.hoo.com>
Sent: Sunday, May 1, 2022 1:11 PM
To: Clerk of the Board
Subject: May 3 Meeting – Item D.2 – Phillips 66 Appeal

Dear Supervisors,

I urge you to reject the land use permit granted by the Planning Commission and require additional EIR reviews for Phillips 66 Refinery biofuels projects and grant the further CEQA reviews requested by the 3 appellants. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use.

The FEIRs inadequately address the following concerns:

- Failure to provide an adequate project description.
- Failure to provide a correct baseline due to lack of petroleum feedstock
- Concern with Unit 250 in the Project Analysis
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.
- Failure to account for impacts of burning food for fuel due to human food used as a "feedstock" in biofuel production
- Failure to consider climate impacts.
- Findings Concerning Choice of Alternatives and Throughput Volumes
- Failure to account for cumulative impacts.
- Failure to provide adequate resources for remediation of the site once it ceased biofuel production
- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency Resolution 2020/256 commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough review of the EIR.

Thank You,

From:	Mike Moore ıoo.com>
Sent:	Sunday, May 1, 2022 1:22 PM
To:	Clerk of the Board
Subject:	May 3 Meeting – Item D.1 – Marathon Appeal

Dear Supervisors,

I urge you to reject the land use permit granted by the Planning Commission and require additional EIR reviews for Marathon Refinery biofuels projects and grant the further CEQA reviews requested by the appellants. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use.

The FEIRs inadequately address the following concerns:

- Failure to provide an adequate project description.

- Failure to provide a correct baseline due to shutdown of the refinery operations

- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.

- Failure to account for impacts of burning food for fuel due to human food used as a "feedstock" in biofuel production

- Failure to consider climate impacts.

- Findings Concerning Choice of Alternatives and Throughput Volumes

- Failure to account for cumulative impacts.

- Failure to provide adequate resources for remediation of the site once it ceased biofuel production

- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency Resolution 2020/256 commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough review of the EIR.

Thank You,

Mike Moore

From: Emily Wheeler <[illegible]m>
Sent: Sunday, May 1, 2022 2:22 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional Environmental Impact Reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Emily Wheeler

Walnut Creek

Stacey Boyd

From: Debi Clifford
Sent: Sunday, May 1, 2022 6:20 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

As a longtime Contra Costa taxpayer and landlord, I urge you to reject the land use permits for the Phillips 66 and Marathon Refinery biofuels projects and conduct more thorough environmental impact reviews.

In this crucial moment, the County has the leverage of the permitting process to insist that these two companies do the hard work now of proving that these projects will not irremediably and significantly harm local residents, our communities, our food supply, and the environment.

To date, the companies have failed to comply with the ***CEQA requirement to respond to public comments,*** as they have not responded in detail to the concerns submitted in writing by local environmental groups. Specifically, they have failed to address:

- ***Safety and air pollution concerns*** *from potentially increased operational hazards including flaring, explosions, gas releases, and increased use of hydrogen*
- ***Impacts of burning food*** *for fuel due to human food used as "feedstock" in biofuel production*
- ***Climate and other environmental impacts***

Please do your due diligence now: don't rubber-stamp this project in your haste to nail down a solution to our county's overdependence on local fossil fuel production. You have the responsibility and authority to take more time to thoroughly analyze these biofuels conversions which offer a seductive energy alternative that – like the Trojan horse – more likely will unleash untold harm on local residents and exacerbate the climate crisis we all face.

Thank you for your service and for your serious attention to this matter.

Sincerely,

Debi Clifford
Richmond, CA

From: Jeffrey Mann <[redacted]t>
Sent: Sunday, May 1, 2022 9:55 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I have lived in CCC for 25 years, and have raised my family here.
I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you for your consideration.

Jeffrey Mann, MD
Lafayette

From:	Vanessa Warhei:
Sent:	Sunday, May 1, 2022 11:26 PM
To:	Clerk of the Board
Cc:	John Gioia
Subject:	Reject the EIRs for proposed Renewable Fuels Project

Dear Contra Costa Supervisor,

I am very concerned about the proposed biofuel projects currently under consideration. I understand that these projects purport to improve the health and climate impacts of the existing refineries, but the facts do not seem to support either of these assumptions -- if anything they point to increasing both GHG impacts and health impacts to our local communities.

I therefore urge you to reject the land use permit and require additional EIR reviews for both Phillips 66 and Marathon Refinery biofuels projects. I am very concerned that joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project, yet the responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. Specifically, the FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. I applaud you for taking this step -- now it's time to take the next step, and demand the refineries come back with a more thorough EIR so you can make an educated decision about the merits of these proposals.
Thank you for protecting our communities. I look forward to hearing back from you on this issue.

Warm regards,
Vanessa Warheit
El Cerrito, CA

--
Vanessa Warheit

Phon

EV Charging Access for All

Emerge CA Class of '21

pronouns: she, her, hers
https://linktr.ee/vwarheit

From: Marinell Daniel < ail.com>
Sent: Monday, May 2, 2022 7:43 AM
To: Karen Mitchoff; John_Gioia; Supervisor Candace Andersen; Diane Burgis
Cc: Clerk of the Board
Subject: Items D1and D2, BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Regards,

Marinell Daniel,

..., El Sobrante, CA 94803

Sent from my iPad

From: Elena Engel < il.com>
Sent: Monday, May 2, 2022 7:52 AM
To: Clerk of the Board
Subject: Biofuels EIRs

The EIR does not take into account all of the impacts from refining biofuels. One of the most egregious omissions is that biofuels have been shown to create more greenhouse gases than they avoid. The use of food crops for fuel is an unfortunate choice with many unintended consequences, including driving up the cost of commodities, and using more ghg-creating inputs when growing such crops.
Biofuels are not the answer. They continue to pollute the air around the refineries and they continue to create unacceptable amounts of greenhouse gases.
I urge you to reject this application, and require an actual EIR that takes into account all the impacts, rather than cherry picks what will appear more advantageous,
Elena Engel
San Francisco

From:	Helena Birecki · |>
Sent:	Monday, May 2, 2022 11:01 AM
To:	Clerk of the Board
Subject:	Uphold the Appeals of Renewable Fuels Projects EIRs-- press pause on these projects

Dear Supervisors,

Please uphold the appeals from numerous community and environmental groups-- put a pause on the projects until the companies do a more thorough EIR that addresses the inadequacies brought up in the appeal.

It is essential that you reject the EIR as it stands not only for public health and safety, but also legal precedent that will negatively impact Contra Costa County first, and then communities across the country.

Especially concerning for public health and safety is the:

- Near-term increased risk of flaring and risk of explosion due to increased use of hydrogen for biofuels processing
- Medium term increased risk of food shortages due to so much agricultural land being shifted from food production to fuel feedstock, and
- Long-term risk of these refineries shutting down with no decommissioning plans

Especially concerning for legal precedent would be:

- Approving an Environmental Impact Report that fails to comply with legal requirements including providing an adequate project description and adequately responding to public comments.

Please uphold the law by upholding the appeals. Put a pause on the two renewable fuels projects until a more legally sound EIR that adequately addresses public health and safety is completed.

Thank you,
Helena Birecki
member of 350 Bay Area

From: Scott Bartlebaugh < al.net>
Sent: Monday, May 2, 2022 11:03 AM
To: Clerk of the Board
Subject: Public Comment on agenda item D2 Hearing regarding Rodeo Renewed project, Board of Supervisors meeting Tuesday May 3, 2022

Clerk, Board of Supervisors,

I submit the following public comment on behalf of the Crockett Improvement Association.

May 2, 2022

Re: Comment on Phillips 66 Rodeo Renewed Project -- Community Benefit Agreement

Contra Costa County Board of Supervisors,

I'm making a comment representing the Crockett Improvement Association regarding the Phillips 66 Rodeo Renewed Project Public Hearing. We believe the project has positive aspects such as a reduction in total emissions, a reduction in hazardous materials and process safety risk to the surrounding public, as well as supports an overall move to lower impact energy sources.

We have concerns with the current lack of definition of the Good Neighbor Agreement. Crockett, Port Costa, and Tormey are fenceline communities that are affected by the planned operation, permitted emissions, and any unplanned incidents that may occur in the course of operation. We request that the Crockett, Port Costa, and Tormey communities be included in discussions of the details of the Community Benefit Agreement. While this may be the plan it was not clear from the discussion at the Planning Commission hearing. This is a matter of environmental justice. A variety of incidents are documented on the Contra Costa County Health Services website, https://cchealth.org/hazmat/accident-history.php, including the Catacarb release in 1994 and incidents as recent as 2015. Crockett was included in a Good Neighbor Agreement following the 1994 Catacarb incident resulting in payments to the Crockett Community Foundation, and we believe a similar agreement with benefit through the Crockett Community Foundation would be appropriate.

Furthermore we believe the Crockett Community Foundation is the most appropriate body and means to administer the management and distribution of funds to the Crockett, Port Costa, and Tormey community. The Crockett Community Foundation has a significant track record of administering other Community Benefit Agreement, mitigation, and similar funds to the community. They are an elected board and have a track record of financially responsible and community engaging management of such funding.

Lastly we ask that odor control from the new project be managed with a well defined performance and enforcement structure. While the new project reduces hazardous materials inventories and

From: Roland Saher < >
Sent: Monday, May 2, 2022 1:45 PM
To: Clerk of the Board
Subject: Reject Renewable Fuels Project's EIRs

Dear Contra Costa Supervisor,
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
    - **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough EIR.

Even though I am not a resident of Contra Costa County - I live in Live Oak, near Capitola - I believe that this is a precedent setting plan that might well affect all parts of California in a negative way and calls, therefore, for a stringent EIR.
Thank you.
Roland Saher

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

	Letters received for Board consideration **Packet 3**			
Pg 1	Valerie Ventre-Hutton	5/3/2022		oppose
Pg 2	Rebecca Auerbach	5/3/2022		oppose
Pg 26	Maureen Brennan	5/3/2022		oppose
Pg 27	Nanlouise Wolfe	5/3/2022		oppose
Pg 28	Kathy Kerridge	5/3/2022		oppose
Pg 29	Gail Susan Gordon, LMFT, SEP	5/3/2022		oppose
Pg 31	Kathleen Rodgers	5/3/2022		oppose
Pg 32	Woody Hastings, The Climate Center	5/3/2022		oppose
Pg 35	Lisa Argento Martell	5/3/2022		oppose
Pg 36	Lis Sibony	5/3/2022		oppose

Stacey Boyd

From: Valerie Ventre-Hutton [redacted]
Sent: Monday, May 2, 2022 4:43 PM
To: Clerk of the Board
Subject: May 3rd BOS meeting: Marathon and P66 biofuels projects/FEIRs

Dear Contra Costa Supervisors,

As a long-term resident of Contra Costa County, I ask that you slow down the EIR process on the Phillips 77 and Marathon Refinery biofuels projects and demand EIRs that are significantly more comprehensive, specific, and address community concerns.

Multiple community and environmental groups submitted joint comments on the draft EIRs that included detailed, specific points about numerous technical aspects of the project. In contrast, the final EIRs provide generalized, vague responses and are dismissive of many impacts that require mitigation including:

- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts, especially in light of CCC's Declaration of Climate Emergency;*
- ***Failure to account for cumulative impacts***
- *Failure to Comply with the CEQA Requirement to Respond to Public Comments*

If one purpose of CEQA is to create actions to mitigate environmental impacts, then the documents submitted are inadequate, potentially in violation of CEQA, and more importantly do not provide the foundational guidance needed to safeguard communities and our county. These projects *must* have a more thorough EIR.

Thank you for your work on behalf of our Contra Costa communities.

Valerie Ventre-Hutton

[redacted] Walnut Creek, CA

Stacey Boyd

From: Rebecca Auerbach [redacted]
Sent: Monday, May 2, 2022 4:48 PM
To: Clerk of the Board
Subject: Please reject the EIRs for biofuels projects

Dear Supervisors,

I am deeply concerned about the proposed biofuel projects at local refineries. Biofuels are a false solution. They offer only a new way to emit greenhouse gasses and threaten the health and safety of frontline communities, in stark contrast to the real climate solutions in sustainable electrification.

I urge you to reject these land use permits, require more thorough Environmental Impact Reports, and regard these projects with extreme wariness about their effects on our community and the climate.

Regards,

Rebecca Auerbach
Pleasant Hill, CA

RODEO CITIZENS ASSOCIATION

5/2/22

To: Contra Costa Board of Supervisors, and,
County Planning Commission of Contra Costa County Dept. Of Conservation & Development

As a group of concerned citizens of the town of Rodeo, we are respectfully requesting an appeal of the Planning Commission's decision to recommend approval of the Phillips 66 Rodeo Renewed land use permit.

Our grounds for appeal are these:

- The details of the Community Benefits Agreement and the conditions of the project are insufficiently defined as to the magnitude and nature of any actual benefit. The decision on this land use permit should be tabled until the details of this agreement are in place. (1)

- Rodeo is classified as a disadvantaged community by Contra Costa County. SB 1000 requires Contra Costa County to integrate environmental justice into the General Plan. This law is based on the understanding that certain communities have experienced a combination of historic discrimination, negligence, and political and economic disempowerment. We here in Rodeo have long experienced a disproportionate burden of pollution and health impacts, noise and odors. (2)

- Phillips 66 has claimed an "extensive odor remediation program" with no details. Details of the plan should be a condition for approval before the permit is granted.

- The hydrogen plant has been ignored in the draft EIR, nor addressed by the Planning Commission. The Air Liquide plant is not capable of the planned increase of methane-fuel consumption, which risks explosion, and at the least, increased flaring events. Investigation of the capability of this plant facility should also be a condition for approval before the permit is granted. Air Liquide has a history of yearly "unit upset" since it went on line in 2009.

Thank you for considering our concerns.

Rodeo Citizens Association, members;

Janet Pygeorge, President; Rodeo
Janet Callaghan; Rodeo
Mike Coody; Rodeo
Elaine Wander; Rodeo
Bod Houseman; Rodeo
Charles Davidson; Hersules
Please respond to RCA:
2108 Drake Lane Hercules CA 94547
(510) 837-8441
CDavidson

____

And Maureen Brennan; Rodeo

____

1) The Rodeo Renewed Project is planned on being an 80,000 barrel per day project for refining 1.22 billion gallons per year. At up to $3.32 per gallon for California Low Quality Fuel Standards credits and Federal Renewable and Blenders Tax credits, up to $3 billions yearly in subsidies (and in-kind subsidies) could be provided to the refinery to produce renewable diesel. If only one cent per gallon from those subsidies were to be provided to the Town of Rodeo as a community benefits package within a Good Neighbor Agreement, $12 million yearly could go to community improvements, such as recreation, education, nature and aesthetics.

- Overcapacity Looms as More and More US Refiners Enter Renewable Diesel Market. Stratas Advisors. (June 11, 2020) https://stratasadvisors.com/Insights/2020/06112020LCFS-RD-Investment

2) Demographics: The town of Rodeo, where the Phillips 66 refinery is located, is a minority-majority and working-class community impacted by heavy exposure to pollution and other hazards. Sixty-six percent of Rodeo's population of 8,679 consists of people of color: 34% is Hispanic, 17% is Asian American, and 15% is African American, according to 2018 U.S. Census estimates. Forty-four percent of its population is white.(1) Rodeo is a low-income community, with a per capita income of $34,356, according to U.S. Census 2018 estimates. The Census places the poverty percentage at 14%, although CalEnviroScreen 3.0 doubles that figure, indicating that 31% of Rodeo's residents live below twice the federal poverty level.(2) A largely African-American community lives in county-owned Section 8 housing located directly at the Phillips 66 refinery fenceline. Little population growth and new home building is expected in Rodeo and there is no supermarket.

It is designated by the State of California, as a Disadvantaged Community by the Office of Environmental Health Hazard Assessment (OEHHA), and assigned a CalEnviroScreen 3.0 percentile of 80-85% (per Sept 2021). This ranking indicates that its residents endure a greater combination of pollution and other environmental stressors than 80-85% of the state. Healthwise, Rodeo falls within the 98th percentile for asthma and 92nd percentile for low birth weight, and within the 75th percentile for cardiovascular impacts. Its exposure to hazardous waste places it in the 98th percentile, to impaired water within the 86th percentile, and to toxic releases within the 78th percentile. (2) As part of the Rodeo-Hercules Fire Protection District, Rodeo has three times the per capita emergency medical response rate as the adjacent middle-class community of Hercules. In addition to its burden of disproportionate environmental harms and public health deficits, Rodeo is also an unincorporated community with a paucity of available services. The absence of a municipal government and the ongoing inadequacy of material resources are two major factors that contribute to the historic lack of being qualified for additional outside resources.

1. https://www.census.gov/quickfacts/fact/table/rodeocdpcalifornia,US/PST045218
2. See https://oehha.ca.gov/calenviroscreen/maps-data.

Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.
charlesdavidson@me.com Hercules CA. 11 April 2022

11 April 2022 [Updated 4/21/2022]

Re: Appeal of Contra Costa County Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project (File No. LP20-2040 and the Contra Costa County Code, section 26-2.2406)

To the Contra Costa County Board of Supervisors:

The appellant requests that the Board of Supervisors grant this appeal, to reject certification of the Phillips 66 San Francisco Refinery Rodeo Renewed Project FEIR, and instruct the Contra Costa County Department of Conservation and Development and the Planning Commission to develop a revised DEIR, that meets the requirements of CEQA, to be prepared and circulated for public comment.

The Phillips 66 Refinery's Rodeo Renewed Project Draft Environmental Impact Report (DEIR) and Final EIR did not acknowledge that making refinery biodiesel, or so-called renewable diesel, from hydrogenated vegetable oils and animal fats is as energy-consuming, carbon dioxide (CO2) greenhouse gas emitting and "carbon-intensive" to refine as the world's dirtiest, most dense and highest sulfur crude oils.

This appeal, is based exclusively upon the refinery portion of the total carbon intensity of renewable diesel and counterintuitively, is solely focused on the exceptionally high carbon intensity needed to process triglyceride oils into renewable diesel fuel. Notably, on a per barrel basis, the Phillips 66 Refinery's anticipated post-Project per barrel Renewable Diesel CO2 emissions would greatly exceed the per barrel CO2 emissions of the refinery's current average high-sulfur, heavy petroleum feedstock.

The County planning commission decision to certify the Final Environmental Impact Report 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 argument set forth in this appeal letter; the comments submitted concerning the failure of the Draft Environmental Impact Report (DEIR) and Final EIR (FEIR) to provide an adequate pre-project, per barrel carbon intensity baseline, which would demonstrate the post-project, per barrel, carbon intensity increase. The DEIR and FEIR also failed to provide an adequate project description which would justify the Project's renewable diesel product as factually low-carbon.

The project's DEIR and FEIR described a renewable diesel product which is inconstant with California climate pathways and neither document justified the project's renewable diesel product as qualified for California Low Carbon Fuel Standard (LCFS) credit-based subsidization.

Failure to provide an adequate project description.
Improper baseline.
Inconsistency with California climate pathways.

I

The DEIR and the FEIR do not clearly demonstrate that the refinery's product is low in embedded carbon dioxide emissions, as required by the California Air Resources Board's Low Carbon Fuels Standard's certification process. The actual numbers published in Phillips 66's own DEIR for their Project, which stipulated expected energy usage, hydrogen requirements and CO2 greenhouse gas emissions, when analyzed, clearly indicate that their renewable diesel (on per barrel basis) is extraordinarily energy-intensive to process and thus, is not a low-carbon product.

Instead of being a feedstock for low-carbon fuel refining, animal fat and vegetable oil molecules are triglycerides (like which physicians measure), and they, counterintuitively, are far more difficult to crack than petroleum oils. The most energy-intensive hydrocracking process for renewable diesel is the hydro-deoxygenation (hydrodeoxygenation) reaction, for which the refinery must greatly expand it hydrogen usage. Renewable diesel fuel produced from a wide array of vegetable oils and animal fats is referred to technically as Hydro-processed Esters and Fatty Acids (HEFA).

In the political or regulatory sphere, if renewable diesel were understood quantitatively as not being a true low-carbon diesel substitute, then such projects would not be certified to qualify for and be approved for California Low Carbon Fuel Standard (LCFS) credits and Federal subsidies.

In the Phillips 66 FEIR master response misleadingly states: "As proposed, the Project would lower facility-wide GHG emissions by about 24,000 MT per year compared to baseline operations. Refer to Table 4.8-5 in the Draft EIR "Annual Project Operational GHG Emissions". This is slightly over only one-percent (1%) of the total project emissions, which is misleading, in that the embedded per barrel CO2 emissions will vastly increase from before the project when refining petroleum feedstock.

However, the basis for the refinery to obtain LCFS credits is that refinery must produce low carbon intensity fuels (on a per barrel basis), although the refinery's DEIR and FEIR only refers to the total refinery greenhouse gas reduction and not the project's future per barrel CO2 emissions increase. LCFS does not require that the whole refinery reduce their total yearly CO2 greenhouse gas emissions, which is due in large part to the decommissioning of obsolete or otherwise stranded assets. In the case of Phillips 66, the reduction in *total* refinery CO2 greenhouse gas derives from decommissioned stranded assets due to the closure of the company's San Luis Obispo County refinery (which had serious long-term decreases of crude availability, as it had no sea port), their planned closure of their problem-laden Line-200 pipeline (which delivered semi-processed petroleum from SLO County to Rodeo), as well as closure of the Carbon Plant on HWY 4.

Uniquely, the Phillips 66 refinery in Rodeo Contra Costa County, is planning on being the world's largest Renewable Diesel biofuels refinery in the world and is about 12 miles away from the Martinez Marathon refinery, which is planning on being the world's second largest biofuels refinery.

For its part, Marathon claims a reduction in carbon dioxide greenhouse gasses of 60% in their renewable diesel project. However, that 60% CO2 reduction comes entirely from the 60% smaller daily throughput_specified by the project and is entirely NOT from the decreased carbon intensity of the renewable diesel, itself. (1)

Similar for Phillips 66's decreased stated project throughput, where the refinery will experience a minimum 33% decrease in throughput (from a 4-year pre-COVID average capacity utilization) of 105,000 barrels per day to a maximum of 80,000 bpd. However, for both refineries, the per barrel CO2 carbon intensities for renewable diesel will actually *increase* significantly (despite the decrease in throughput), because of the corresponding large increase in hydrogen needed for hydrocracking triglyceride oils. (2a-d)

For example, despite the shimmer of Marathon's 60% decrease in throughput, a simple look at their 42% *increase* in total hydrogen production (made from fossil-fuels), combined with their simultaneous *decreased* throughput, results in a 32% per barrel *increase* in carbon intensity. (1)

Again, similar to Marathon, post-Project refinery-wide, Phillips will be producing 35% more hydrogen than with petroleum refining and delivering a renewable diesel product with a 36%-to-55% increase in per barrel Carbon Intensity at the refinery level. (2) [Table 1]

The projected Phillips 66 and Marathon Renewable Diesel products, when compared to the processing energy requirements for heavy petroleum refining, would be twice as carbon intensive as the average U.S. refinery's processing of petroleum and as high or higher than the most carbon intensive refineries. (3-7) [Table 2]

II

"The Petroleum Refinery Life Cycle Inventory Model (PRELIM) is a mass and energy-based process unit-level tool for the estimation of energy use and greenhouse gas (GHG) emissions associated with processing a variety of crude oils within a range of configurations in a refinery." (6)

The following analysis closely correlates the carbon intensity of the Phillips 66 and Marathon projected Renewable Diesel products with a characteristic petroleum diesel hydrocracker assessed in the PRELIM database, which was fed with a high-sulfur, heavy petroleum gas oil (API 14.96; Sulfur 3.35%). The hydrogen usage for the PRELIM heavy, high-sulfur fed hydrocracker is (listed in the footnoted references and Table1), is 36% below the much higher values for the average renewable diesel profiled in this paper. (6) [Table 1]

One can see that the pre-project refinery-level carbon intensity values, as kilograms of CO2 per barrel, for Marathon (49.52 kg CO2/bbl) and especially Phillips 66 (56.68 kg CO2/bbl) are close to the PRELIM hydrocracker carbon intensity score (58.97 kg CO2 /bbl). (1,2 6) Table 2.

These values are well above the average U.S. refinery carbon intensity (40.7 kg CO2e/bbl), as would be expected from the type of petroleum crude that these refineries currently process. (7)

Staring from these baseline values and based upon the refineries' hydrocrackers projected post-project hydrogen requirements, one can see that post-project carbon intensities for renewable diesel rank at the top end of global crude carbon intensity scores (according to the PRELIM database). The global-weighted refinery-level carbon intensity range for crude oil processing is 10.1 – 72.1 kg CO2e/bbl. This is true for the projected post-project carbon intensity scores for renewable diesel production for Marathon (65.35 CO2 kg/bbl) and Phillips 66's Rodeo Renewed Project for both the low estimate 73.53 CO2 kg/bbl and especially, the high estimate 87.79 CO2 kg/bbl (for 80,000 or 67,000 barrels per day scenarios, respectively). See Table 2. (8)

III

The California Air Resources Board (CARB) designates and regulates the CO2 greenhouse gas or carbon intensity (CI) for California transportation fuels, whether they are petroleum based or biodiesel, which includes renewable diesel. According to CARB, "The CI includes the "direct" effects of producing and using the fuel, as well as "indirect" effects that are primarily associated with crop-based biofuels." About 75 percent of the GHG emissions from the well-to-wheel life of California Reformulated Gasoline and petroleum diesel are tailpipe emissions. Fuels and fuel blendstocks introduced into the California fuel system that have a CI higher than CARB benchmark Low carbon Fuel Standard generate deficits. Similarly, fuels and fuel blendstocks with CIs below the benchmark generate LCFS credits as a low-carbon fuel.(8)

Based upon the numbers presented in Phillips 66 Refinery's Rodeo Renewed Project Draft Environmental Impact Report, the calculatable and thus, post-project high refinery-level carbon intensity of renewable diesel is elevated far above the refinery's current average petroleum processing carbon intensity, on a per barrel basis and approach the total well-to-wheel carbon intensity of petroleum diesel refining. According to calculations presented in this appeal, renewable diesel should not qualify for LCFS credits. (8)

Specifically, for the Phillips 66, Refinery, this indicates that the Rodeo Renewed Project's carbon intensity for renewable diesel, 86.77 g/MJ will reach par with CARB's entire well-to-wheel petroleum diesel carbon intensity (Low Carbon Fuel Standard) benchmarks in the up-in-coming calendar years 2024 or 2025, at between 87.89 g/MJ or 86.64 g/MJ, respectively. (8)

Renewable Diesel refinery-level carbon intensity, is also nearly on par with the entire well-to-wheel life cycle assessment of California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and greatly exceeds it at the refinery-level. (According to CARB, "CARBOB makes up the petroleum fraction of California reformulated gasoline (CaRFG) before any fuel oxygenate is added; CARFG is essentially 90 percent CARBOB blended with 10 percent ethanol by volume.") (8)

For comparison of petroleum CARBOB carbon intensity with to the much higher renewable diesel carbon intensity findings presented in this appeal, "CARBOB CI is based on the 2010 average crude oil supplied to California refineries and average California refinery efficiencies. Production of CARBOB at all California refineries adds [only] 15g/MJ to the fuel cycle CI. (8)

Furthermore, the high refinery-level carbon intensity for renewable diesel is similar for the Marathon Renewable Project in Martinez. The refinery-level (midstream) Carbon Intensity scores of the Marathon and Phillips 66 Renewable Diesel projects are 77.11 g/MJ and 86.76 g/MJ, respectively, and are both well over three times the CARBOB refinery-level carbon intensity score, of 15 g/MJ.

The contrast with renewable diesel's high refinery-level carbon intensity is even greater for non-hydrogenated biodiesel, called fatty acid methyl ester FAME, such as made from used cooking oil, which has a very low refinery-level carbon intensity score of 11 g CO_2/MJ. While renewable diesel can entirely substitute for 100% of petroleum diesel in diesel vehicles, FAME has poor flow in cold conditions, and is generally required to be blended with petroleum diesel at no more than a 7% FAME in the EU and 5% in the US, except for up to 20% for some fleets with modified engines. (8) Table 2.

CO_2 GHG emissions from land-use changes (LUC) for both FAME biofuels and hydrotreated renewable diesel production are assumed at 30 g CO_2e/MJ for soybean oil. When soybean oil's embedded 30 g/MJ LUC CO_2 greenhouse gas is added to the projected refinery-level renewable diesel (HEFA) CO_2 greenhouse gas emissions from both the Phillips 66 and Marathon refinery projects, these values significantly exceed the total CO_2 greenhouse gas embedded in petroleum diesel (despite tailpipe CO_2 emissions being discounted for renewable diesel, as for FAME).

Because of the general need for more intensive hydrocracking than Renewable Diesel, Sustainable Aviation Fuel made from hydrogenated vegetable oils and animal fats should have a possibly higher refinery-level carbon intensity score and thus, also not qualify of LCFS credit certification.

Table 1: Renewable diesel versus petroleum refining - per barrel hydrogen requirements

Hydrogen per barrel - scf /barrel		PRELIM	PRELIM +35%	Marathon	Phillips 66	Algal	HT	Karras	Average
		Petroleum	RD - theoretical	RD	RD	RD	RD	RD	RD
Renewable Diesel			2463.35	2497.45	2119.4	3062.5	2451	2270	2480.07
Petroleum		1824.7		655	1000				
Column		1	2	3	4	5	6	7	8
[Reference/footnote]		[6]		[1]	[2]	[4]	[3]	[5]	
		1	2	3	4	5	6	7	8

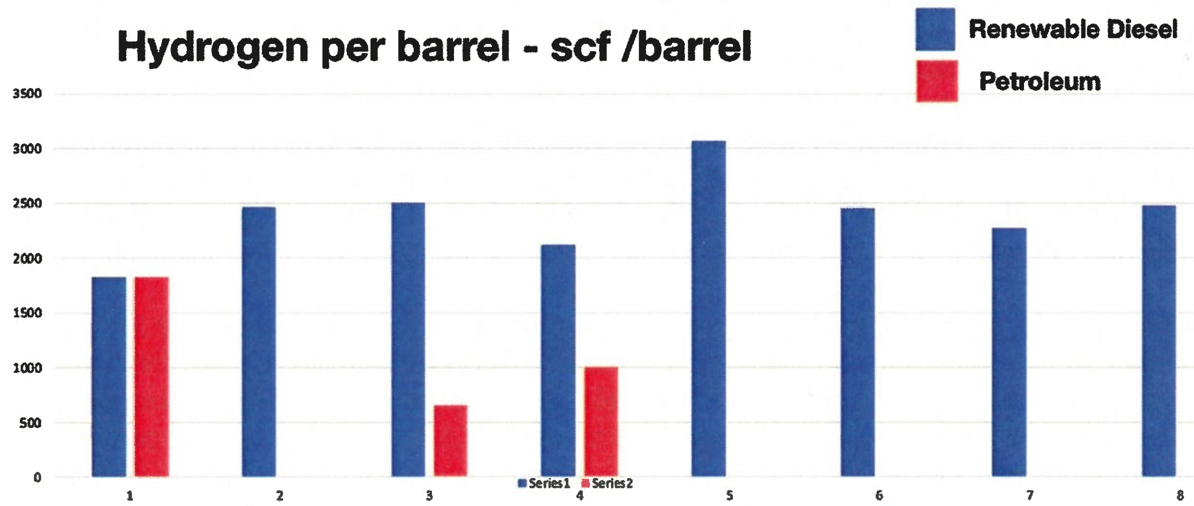
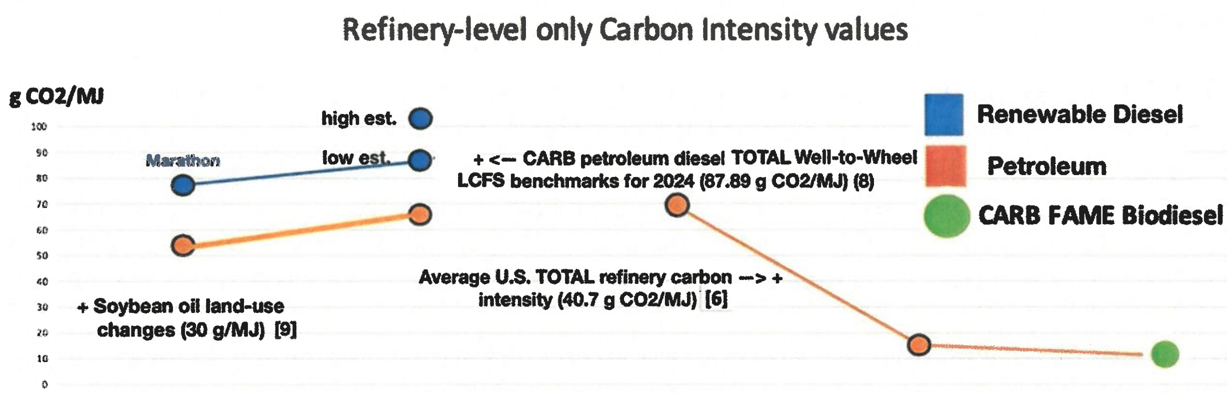


Table 2: Refinery level (midstream) carbon intensity / CO2 greehouse gas emissions only: : g CO2/MJ (kg CO2/bbl)

	MARATHON	PHILLIPS 66	PRELIM *	CARBOB **	CARB Biodiesel ***
Post project Renewable diesel - Marathon and Phillips 66:	77.11 (65.35)	86.77 (73.53)			
Petroleum Diesel* CA gasoline** Non-hydrotreated biofuels***			69.71 (58.97)	15	11
Pre-project (refinery-wide)	54.36 (46.07)	66.88 (56.68)			
	1	2	3	4	5
References and footnotes	(1) RD	(2) RD Low estimate	(6) Petroleum Diesel API 14.96; S-3.35%	(8) Petroleum CA gasoline-No ethanol	(8) FAME: Fatty Acid Methyl Ester



IV

To summarize, the true high refinery-level carbon intensity at a renewable diesel-configured refinery (as grams of CO2 per megajoule and equivalently, the kilogram per barrel CO2 emissions) have not been divulged in plain language, tabular form or graphically in either the Draft EIRs and Final EIRs for the Phillips 66 Refinery's Rodeo Renewed Project (and similarly for the Marathon Renewable Project). However, calculations can be performed on the numbers available in the Phillips 66 Draft EIR and other documents which show that renewable diesel, because it is so intensely hydrogenated, has a refinery-level carbon intensity value, on a per barrel- and per Megajoule-basis (as required by the California Air Resources Board), rivalling that of the heaviest globally-available crude oils.

So, what is currently being proposed in Contra Costa County, at the Phillips 66 Refinery, as well as the Marathon Refinery, are very expensive, publicly-funded, carbon-intensive renewable diesel projects, which are erroneously being promoted as sources of low-carbon fuel and so should be disqualified for California Low Carbon Fuel Standard Credits.

As the availability of used cooking oils and waste animal fat markets will be competitive and limited once multiple large refineries enter the renewable diesel business, the default principal feedstock is expected to be soybean oil in the reasonable future. At a yield of only 57 gallons of soybeans per acre, however, Phillips 66 alone could annually use up to 33,000 square miles of soybean acreage or nearly the size of the State of Indiana, for its expected 1.22 billion gallons of renewable diesel produced yearly. (10)

Financially, refinery biodiesel is being funded to the tune of up to \$3.32 per gallon (according to Stratas Advisers, and depending on the feedstock). That could amount to up to \$3 billion *yearly* given to Phillips 66 and \$1.8 billion given to Marathon under false pretenses as producers of low carbon biofuels, which contradicts the massive increase in *per barrel* carbon intensity and global food security. (11)

Finally, the Phillips 66 DEIR states that the refinery's massive delayed coker and catalytic reformer will *not* be decommissioned in this project. Upon this appellant's email request to the refinery's senior engineer, regarding the company's purpose of this retention of equipment, the employee stated that these units' permits will be retained for the purpose of producing battery-grade petroleum coke (i.e., needle coke).

Accordingly, upon Project completion, the senior engineer replied that the retained delayed coker is intended to be used to coke FCC waste "slurry oil" obtained from other refineries in order to produce the battery-grade petroleum coke, Ostensibly, the FCC slutty oil would be a feedstock for subsequent calcining into graphite, at a yet unstated facility, which then would be used for carbon anodes for electrical vehicle batteries.

After the Rodeo Renewed Project is completed, this use of the delayed coker is consistent with the staff's statement that the refinery will no longer be using crude oil, which definitely leaves open the real possibility for a continuation of large-scale petroleum refining beyond the completion of the Rodeo Renewed Project. (12)

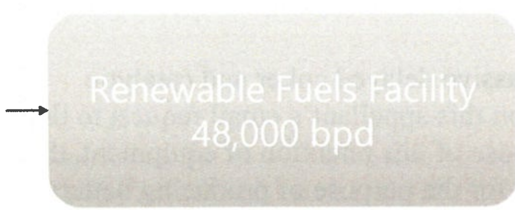
As FCC slurry oil is dirtier than the heavy FCC oils from which it is derived, it also contains more toxic heavy metals than the original FCC feedstock, being concentrated from both the FCC feedstock oil itself (with nickel and vanadium residues) and from the FCC spent catalyst (with additional nickel). The coker's product is always dumped from the bottom of the coker, in an open-air process and the tpractice of the Rodeo refinery is to store the petroleum coke in open piles.

Moreover, the light hydrocarbon (naptha) portion of the slurry oil feedstock will exit from a coker port and would likely be sent to the catalytic reformer to produce either branched hydrocarbons (for use as gasoline octane boosting agents) or more likely, if reconfigured, for the production of hydrogen (which could be used for additional on-site biofuel feedstock hydrotreating). This additional hydrogen can be used to produce more renewable diesel or to improve the conversion efficiency of the companies planned renewable diesel production or to make sustainable aviation fuel at some future point (which requires more hydrogen than renewable diesel production). (13)

The retention of Phillips 66's delayed coker and catalytic reformer and their stated plans for their coker, indicate that the refinery has intentionally retained the option for their continued fossil fuel refining and the possibility for producing significantly higher refinery-wide CO2 emissions than stated within the refinery's Draft Environmental Impact Report.

REFERENCES:

1) Marathon Renewable Project (Martinez CA; PowerPoint Presentation):



	Marathon Martinez	Refinery	Renewables	Delta Mtonnes/Yr
2	Capacity (mbpd)	160	48	
3	MPC GHG H2 Production (MTonnes/Yr)	448	687	239
4	AP GHG H2 Production (MTonnes/Yr)	230	275	45
5	GHG H2 Captured & Sold (MTonnes/Yr)	-56	-56	-
8	GHG All Other Combustion (MTonnes/Yr)	1547	239	-1,308
9	*Total Direct GHG w/ AP (MTonnes/Yr)*	*2169*	*1145*	*-1,024*

~ 60% reduction in GHG as part of project
Will continue to capture & sell 56,000 MT of CO2e

Marathon (calculations based on reference #1 and the DEIR's stated full refinery capacity of 125,000,000 scf/d):

REFINERY THROUGHPUT:

Pre-Project (Baseline):
Barrels (4-year avg. throughput; 161,000 bbl/d capacity): 129,000 bbl/d * 365 = 47,085,000 bbl/y

Decrease in total refinery throughput (4-year avg. throughput; 161,000 bbl/d capacity:
(129,000 – 48,000 = 81,000) / 129,000 = 0.6 = - 63% decrease in throughput

Pre-Project (Baseline):
Barrels (4-year avg. throughput; 161,000 bbl/d capacity): 129,000 bbl/d * 365 = 47,085,000 bbl/y

HYDROGEN PRODUCTION, REFINERY-WIDE:

Full refinery Hydrogen (H2) capacity: 125000000 scf/d/ 423 scf/kg * 365 d/y * 9.3 kg CO2/ kg H2 / 1000 kg/MT = 1,003,102 MT/y

Hydrogen capacity utilization: 1,003,102 MT/y / 962,000 MT/y= 0.959 → 4% reduced from full refinery capacity

Post-project 962,000 MT/y from pre-project 678,000 MT kg/y

Pre-to-Post project hydrogen production increase (project total):
962 MT/y / 678 MT/y= 1.42 → + 42% (increase in total H2-plant CO2 emissions)

HYDROGEN PRODUCTION, PER BARREL:

Pre-project hydrogen per barrel:
678,000 MT kg/y / * 1,000 kg/MT / 365 d/y/ 9.3 gCO2/gH2 / 129,000 bbl/d* 423 scf/kg= 654.94 scf/bbl = 1.55 kgH2/bbl

Post-project refinery-made hydrogen per barrel:
962,000 MT/y * 1,000 kg/MT / 9.3 / 365 / 48,000 bbl* 423scg/kg = 2497.46 scf/bbl = 5.9 kgH2 /bbl

Pre-to-Post project hydrogen production increase (project total):
962 MT/y / 678 MT/y= 1.42 → + 42% (increase in total H2-plant CO2 emissions)

REFINERY CO2 EMISSIONS AND PER BARREL CO2 EMISSIONS:

Decrease in total refinery-wide CO2:
1,145,000 / 2,169,000 = 0.5278 = - 53% (decrease in CO2)

Pre-Project *total* annual refinery CO2 (Carbon Intensity from GHG-to-bbl/y ratio and g CO2/MJ):
2,169,000,000 (kg CO2/y) / 47,085,000 bbl/y = 46.07 kg CO2/bbl → 46.07 * 1.18 = 54.36 g CO2/MJ

Post Project total refinery CO2
Barrels: 48,000 bbl/d * 365 = 17,520,000 bbl/y
CO2 Refinery-wide total: 1,145,000 mt/y * 1000 = 1,145,000,000 kg/y

Post-project Carbon Intensity (CO2 GHG/y-to-bbl/y ratio and g CO2/MJ):
1,145,000,000 kg/y / 17,520,000 bbl/y = 65.35 CO2 kg/bbl
Carbon Intensity (g/MJ): 65.35 * 1.18= 77.11 g/MJ

Pre-to-Post project *per barrel* change in Carbon Intensity (Relative % - refinery-wide):

65.35 / 46.07 = 1.42 → +42% increase in CI

2a) Rodeo Renewed Project (Rodeo CA; 80 K or 67 K barrels per day); Pre-Project (current 105 K bpd):

Table 4.8-2. Baseline Annual GHG Emissions (2019)[1]

Source Category	Baseline Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Refinery				
Ocean-going Vessels and Harbor Craft	15,137	0.15	0.93	15,418
Trucks	4,466	0.02	0.70	4,676
Rail	1,373	0.11	0.03	1,386
Facility Operations	1,333,341	91.96	11.74	1,338,911
Electricity	9,160	1.30	0.28	9,270
Rodeo Refinery Total	1,363,477	94	14	1,396,661
Air Liquide H_2 Plant	801,794	--	--	801,794
Santa Maria Site and Pipeline Sites				
Trucks	2,565	0.01	0.40	2,686
Rail	177	0.01	0.00	179
Facility Operations	171,765	17.30	1.43	172,571
Electricity	5,328	0.76	0.16	5,392
Total Statewide	2,345,107	111.62	15.68	2,352,284
Total within BAAQMD	2,165,272	93.54	13.69	2,171,455

1. 2019 is the CEQA baseline for this analysis for all sources except ocean-going vessels and harbor craft. For vessel emissions, an average of 2017 through 2019 was used.
Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant Site
Air Liquide CO_2e emissions assumed to be entirely CO_2 as the breakdown for CH_4 and N_2O is not available.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. It is expected to change to 25 and 298 respectively for reporting years 2021 and forward.

2b) Rodeo Renewed Project (Rodeo CA); Post-Project (completed):

Rodeo Renewed Project
Draft Environmental Impact Report

Table 4.8-5. Total Annual Project Operational GHG Emissions

Source	Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Renewed Project Emissions				
Ocean Going Vessels and Harbor Craft	26,195	0.28	1.53	26,657
Rail	8,119	0.64	0.20	8,195
Trucks	2,720	0.00	0.43	2,847
Facility Stationary Sources	1,069,772	84.51	10.79	1,075,100
Electricity	1,180	0.41	0.09	2,889
Total Operational	**1,109,661**	**85.84**	**13.04**	**1,115,689**
Air Liquide H_2 Plant	1,031,689	--	--	1,031,689
Total Operational with Air Liquide	**2,141,350**	**85.84**	**13.04**	**2,147,378**
CEQA Impact Evaluation				
Baseline Emissions within BAAQMD	2,165,272	93.54	13.69	2,171,455
Project Minus CEQA Baseline				-24,077
Significance Threshold				10,000
Exceeds Threshold?				No
Statewide Impact Evaluation (informational only)				
Baseline Emissions Statewide	2,345,107	112	16	2,352,284
Project Minus Statewide Baseline				-204,905

Notes: Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. Based on CARB reporting, it is expected to change to 25 and 298 respectively for reporting years 2021 and forward. Therefore, Project facility emissions are based on 25 GWP for CH_4 and a 298 GWP for N_2O.
The GHG emissions for the Air Liquide hydrogen plant are not reduced to reflect the offset provisions of the Settlement Agreement between ConocoPhillips Company and the Attorney General of California, dated September 10, 2007, and amended May 25, 2010.
Air Liquide CO_2e emissions assumed to be entirely CO_2 as breakdown for CH_4 and N_2O is not available.

2c) Air Liquide Hydrogen Plant H2 production; Table 15; Attachment B, Appendix B:

Stationary Source Table 15
Air Liquide Hydrogen Plant Emissions Summary
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

CAP and GHG Emissions

Scaling Method	Baseline Activity	Project Activity	Units	Pre-Project Emissions (tons/year)							Post-Project Emissions (tons/year)							Change in Emissions (tons/yr)						
				NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
Fuel Combustion	756	987	MMBTU/hr	17	0.010	0.95	1.1	3.6	3.5	--	22	0.013	1.2	1.4	4.7	4.6	--	5.1	0.0031	0.29	0.34	1.1	1.1	--
Hydrogen Production	93.26	120	MMSCF H2/day	--	--	--	--	--	--	801,794		--	--	--	--	--	1,031,689	--	--	--	--	--	--	229,895
			Total	17	0.010	0.95	1.1	3.6	3.6	801,794	22	0.013	1.2	1.4	4.7	4.6	1,031,689	5.1	0.0031	0.29	0.34	1.1	1.1	229,895

2d) Unit U110 Phillips 66 Hydrogen Plant H2 Production; table 13; Attachment B, Appendix B:

Stationary Source Table 13
Baseline and Post-Project TAC Emissions from Miscellaneous Project Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source ID	Description	Post-Project Status	Emission Type	Baseline Throughput		Post-Project Throughput		Baseline Emissions[1] (tons/year)							Post-Project Emissions[2] (tons/year)						
				Rate	Units	Rate	Units	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
11	U240 B-201 Heater	Operational	Combustion	56	MMBtu/hr	33	MMBtu/hr	11	13	0.39	1.2	1.6	1.6	29,233	6.8	8.0	0.23	0.71	1.0	1.0	17,492
12	U240 B-202 Heater	Operational	Combustion	16	MMBtu/hr	24	MMBtu/hr	1.8	3.8	0.42	0.34	0.46	0.46	8,271	2.8	5.8	0.64	0.51	0.71	0.71	12,607
13	U240 B-301 Heater	Operational	Combustion	125	MMBtu/hr	93	MMBtu/hr	6.9	30	0.87	2.7	3.7	3.7	66,359	5.2	22	0.65	2.0	2.7	2.7	49,541
45	U246 B-801 A/B Heater	Operational	Combustion	62	MMBtu/hr	24	MMBtu/hr	1.4	0.12	0.82	0.26	0.81	0.81	28,384	0.52	0.046	0.32	0.10	0.31	0.31	10,922
437	Unit 110 Hydrogen Manufacturing Unit	Operational	Hydrogen Plant	12	MMScf/day	22	MMScf/day	--	--	--	--	--	--	100,368	--	--	--	--	--	--	177,642
438	U110 H-1 Furnace (H2 Plant Reforming)	Operational	Combustion	140	MMBtu/hr	225	MMBtu/hr	3.6	4.1	1.3	0.15	4.6	4.6	16,261	5.8	6.7	2.1	0.24	7.4	7.4	26,133

Notes:
1. Baseline emissions were obtained directly from the facility's 2019 BAAQMD Rule 12-15 Emissions Inventory.
2. Post-project emissions were estimated using baseline throughput and emissions and post-project projected rates.

Phillips 66 (calculations based on references #2a, 2b, 2c and 2d):

REFINERY THROUGHPUT; HYDROGEN PRODUCTION: REFINERY-WIDE: AND PER BARREL:

Pre-to-Post total refinery-wide project hydrogen production increase (total from Air Liquide and unit U110):
(120 mscf +22mscf) / (93 mscf + 12 mscf) = 142 mscf / 105 mscf = 1.35 → +35% (increase in H_2 production)

Pre-project *per barrel* refinery-made hydrogen:
105,000,000 scf / 105,000 bbl/d = 1,000 scf/bbl [* 1/423 kg/scf] = 2.36 kg CO_2/bbl

Post-project average *per barrel* refinery-wide hydrogen:
142,000,000 mscf / 67,000 bbl = 2119.40 scf/bbl [* 1/423kg/scf] = 5.01 kg CO_2/bbl

Pre-to-post average *per barrel* refinery-wide hydrogen production ratio:
2119.40 mcf /1,000 scf = 2.12 → 120% increase

Pre-Project: *total* refinery CO_2 (within BAAQMD area):
Barrels: 105,000 bbl/d * 365 = 38,300,000 bbl/y
CO_2 Refinery-wide total: 2,171,000 mt/y = 2,171,000,000 kg/y

REFINERY CO2 EMISSIONS AND PER BARREL CO2 EMISSIONS:

Pre-Project: *total* refinery CO_2:
Barrels: 105,000 bbl/d * 365 = 38,300,000 bbl/y
CO_2 Refinery-wide total: 2,171,000 mt/y = 2,171,000,000 kg/y

Pre-Project (within the BAAQMD area) average refinery per bbl and per MJ CO_2:
Carbon Intensity (CO_2 GHG-to-BPY ratio): 2,171,000,000 kg/y / 38,300,000 bbl/y = 56.68 CO_2 kg/bbl →
Carbon Intensity (g CO_2/MJ) 56.68 * 1.18 = **66.88 g CO_2/MJ**

Pre-Project (In-State) average refinery per bbl and per MJ CO_2:
2,353,000,000 kg CO_2/y / 38,300,000 bbl/y= 61.44 kg CO_2/bbl
2,353,000,000 kg CO_2/y / 38,300,000 bbl/y * 1.18 = 72.49 g CO_2/MJ

Post Project: *total* refinery CO_2 per barrel (low estimate):
Barrels: 80,000 bbl/d * 365 = 29,200,000 bbl/y
CO_2 Refinery-wide total: 2,147,000 MT/y = 2,147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 kg/y / 29,200,000 bbl = 73.53 kg CO_2/bbl
Carbon Intensity (g/MJ): 73.53 kg CO_2/bbl * 1.18 = **86.77 g/MJ**

Post Project: *total* refinery CO_2 per barrel (high estimate): clean fuels
Barrels: 67,000 bbl/d * 365 = 24,455,000 bbl/y
CO_2 Refinery-wide total: 2,147,000 MT/y = 2.147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 kg/y / 24,455,000 bbl/y = 87.79 CO_2 kg/bbl
Carbon Intensity (g/MJ): 89.79 * 1.18 = **105.95 g/MJ**

Pre-to-Post project *per barrel change* in Carbon Intensity (Relative %):
a. 73.53 / 56.68 = 1.3 = **+ 30% → 30% increase in CI (low est.)**
b. 87.79 / 56.68 = = 1.55 = **+ 55% → 55% % increase in CI (high est.)**

3) **Hydrotreating in the production of green diesel.** Rasmus Egeberg, Niels Michaelsen, Lars Skyum and Per Zeuthen. *Haldor Topsøe.*

"As the reactions also consume large amounts of hydrogen (for a 100% renewable feed, a hydrogen consumption of 300–400 Nm^3/m^3 is not unusual), higher make-up hydrogen and quench gas flows are needed even when co-processing quite small amounts."

400 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) = 2451.61 scf/bbl (2451 / 423) = 5.79 kg/bbl * 9.3 = 53.85 CO2 kg/bbl (hydrogen-production only)

300 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) * 0.75 [(300nM3/M3) / 400 (NM3/M3)]= 1838.70 scf/bbl = (1838.7 / 423) = 4.34 kg/bbl = 40.36 CO2 kg/bbl (hydrogen-production only).

4) PATENTED HYDROCRACKER HYDROGEN USAGE FOR AGAEL BIOFUELS REFINING COMPARED TO SOY OIL. [Pub.No.:US2010/0297749A1 ARAVANIS et al. METHODS AND SYSTEMS FOR BIOFUEL PRODUCTION. Pub.Date: Nov.25,2010] (12)

For comparison of algael oil hydrorefining to soy oil and heavy petroleum hydrorefining, a patented algael biofuels protocol was described for hydrocracking, plus hydroisomerization and feedstock hydrotreating, of 80 barrels per day throughput using 245,000 scfd of hydrogen plant H2. The total hydrogen volume required for the described "Integrated Biofuels Refinery" for algael oil is 3,063 scf per barrel, which would place the algael fuel hydrocracker hydrogen consumption at the upper (heavy petroleum) end of the 1,000-3,000 scf per barrel range. Similar large- and small-size algael biofuels hydrorefinery configurations were described in the patent.

5) Changing Hydrocarbons Midstream. Karras, Greg. Community Energy Resource. Table 2. https://www.energy-resource.com/_files/ugd/bd8505_757a3372387d46358c74d958d158fcb5.pdf

Changing Hydrocarbons Midstream

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.

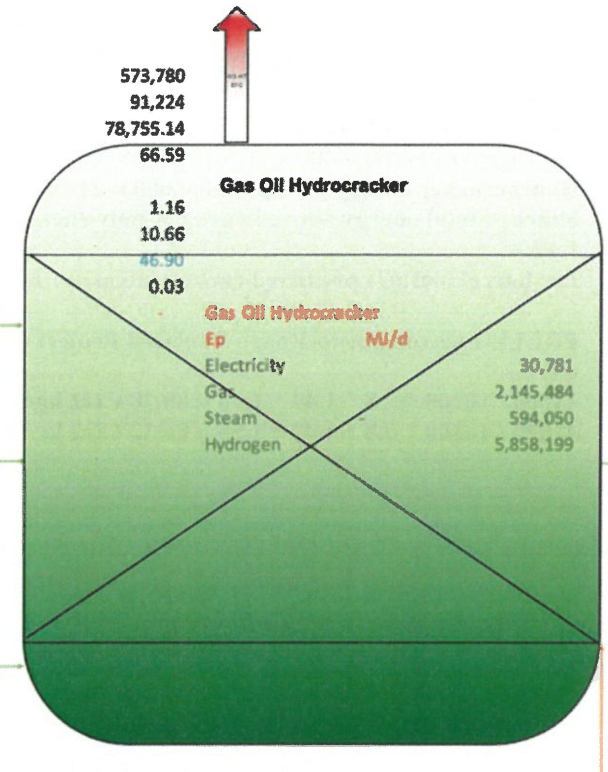
5) ENERGY STAR® Guide: ENERGY STAR is a U.S. Environmental Protection Agency Program for Energy and Plant Managers. (February 2015)
https://www.energystar.gov/sites/default/files/tools/ENERGY_STAR_Guide_Petroleum_Refineries_20150330.pdf

The hydrocracker consumes energy in the form of fuel, steam and electricity (for compressors and pumps)…The reactions are carried out at a temperature of 500-750°F (290-400°C) and increased pressures of 8.3 to 13.8 Bar…The hydrocracker also consumes energy indirectly in the form of hydrogen. The hydrogen consumption is between 150 and 300 scf/barrel of feed (27-54 Nm^3/bbl) for hydrotreating and 1000 and 3000 scf /barrel of feed (180-540 Nm^3/bbl) for the total plant (Gary et al., 2007).

6) Petroleum Refinery Life Cycle Inventory Model (PRELIM) PRELIM v1.3. User guide and technical documentation. Jessica P. Abella et al. [Joule A. Bergerson]
https://www.ucalgary.ca/sites/default/files/teams/477/prelim-v1.3-documentation.pdf
PRELIM 1.3 Hydrocracker with heavy, high-sulfur petroleum feedstock:
14.96 API and 3.35% Sulfur

Gas Oil HC Fuel Gas

Property	Units	
Vol Flow	bpd	573,780
Vol Flow	m^3/d	91,224
Mass Flow	kg/d	78,755.14
Sulphur	wt%	66.59
API gravity	°API	
Density	kg/m^3	1.16
Hydrogen	wt%	10.66
DHc	MJ/kg	46.90
Price	$/bbl	0.03
Allocation	Hydrogen Content Basis	



Gas Oil Hydrocracker Feed

Property	*Units*	
Vol Flow	bpd	10,199.87
Vol Flow	m^3/d	1,621.65
Mass Flow	kg/d	1,566,698.34
Sulphur	wt%	3.35
API gravity		14.96
Density	kg/m^3	966.11
Hydrogen	wt%	11.18
MCR	wt%	-
Total hyd	kg/d	43,911.28
DHc	MJ/kg	39.29
Price	$/bbl	85.54
Allocation	Hydrogen Content Basis	-

PRELIM 1.3 heavy petroleum Hydrocracker (Gravity API 14.96 and Sulfur 3.35%):

Hydrocracker carbon intensity (CI) per day (total):
5.858,000 (H2)+2,145,000 (NG)+594,000 (steam)+31,000(e) = 8,628,000 MJ/d

Share of total hydrocracker energy (CI) above hydrogen-only energy:
8,628,000 MJ/ 5,858,000 MJ = 1.47 (47%)

Hydrogen required, per barrel:
44,000 kg H2/d / 10,200 bbl/d * 423 scf/kg H2 = 1824.70 scf /bbl

Hydrogen-plants daily CO2 emissions per day:
44000 kg H2/d * 1000 g/kg * 9.3 = 409,200,000 g CO2/d = 409,200 kg CO2 /d

Hydrocracker CO2 emissions per day (total):
44,000 kg H2/d * 1,000 g/kg * 9.3 gCO2/gH2 * 1.47 = 601,524,000 g CO2/d = 601,524 kg CO2 /d

PRELIM CO2 emissions, per barrel: (44,000 / 10,200 * 1.47 = 6.34) * 9.3 = **58.97 kg CO2 /bbl**
PRELIM Carbon Intensity: 601,524,000 g/d CO2 / 8,628,000 MJ/d = **69.71 g/MJ**

NOTE: CO2 mass-to-energy conversion factor (ratio): 69.71 g CO2/MJ /58.97 kg CO2/bbl → 1.18

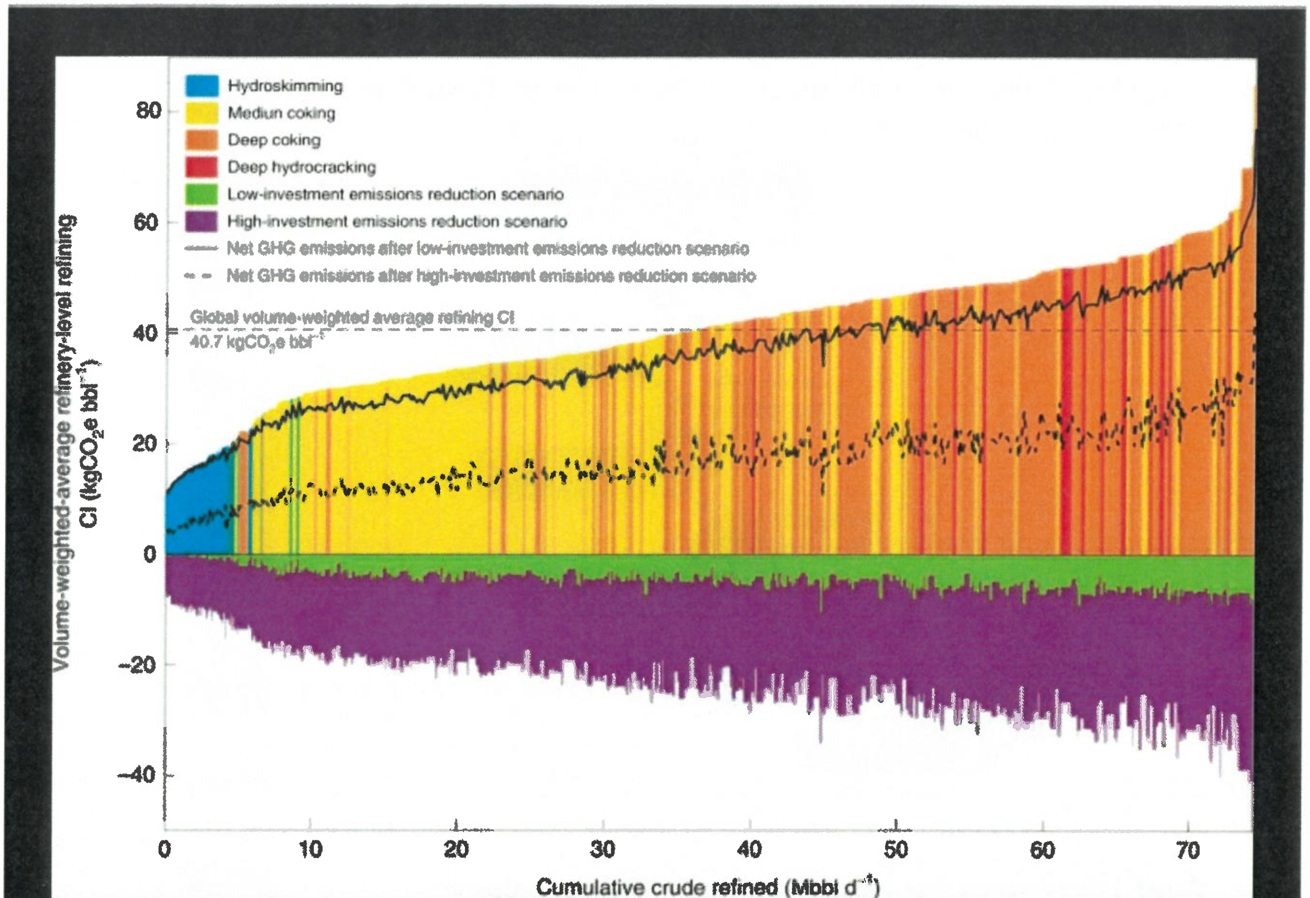
Phillips 66 predicted carbon intensity from +32% increase (w estimate; 80,000 bbl/d case):
58.97 **kg CO2 /bbl** * 1.32 = 77.84 **kg CO2 /bbl**
1.18 * 77.84 kg/bbl => **92.0 g/MJ.**

Phillips 66 predicted carbon intensity from +55% increase (High estimate; 67,000 bbl/d case):
1..18 * 91.4 kgCO2 /bbl => **108.05 g/MJ**

PRELIM petroleum-to-Marathon Renewable Project (+32% increase example; predicted Renewable Diesel CI)
Per barrel biofuels CO2 GHGs +32% inc. over petroleum:
Hydrogen per barrel: 44000 (H2/d) / 10200 (bbl/d) * 9.8 * 1.32 = 55.80 kg/bbl
Hydrocracker energy per day: 5858000 + 2145000 + 594000 + 31000 = 8628000
Share of total energy above hydrogen-only energy: 5858000 + 2145000 + 594000 + 31000 / 5858000 = 1.47
Per barrel biofuels predicted carbon intensity: 1.47 * 55.8 = 82.19 CO2 kg/bbl

PRELIM petroleum-to-Rodeo Renewed Project (high and low estimates; predicted Renewable Diesel CI)
44000 / 10200 * 9.8 * 1.47 * 1.30 = 80.78 CO2 kg/bbl (+30% low case est. per 80,000 bbl/d)
44000 / 10200 * 9.8 * 1.47 * 1.55 = 96.32 CO2 kg/bbl (+55% high case est. per 67,000 bbl/d)

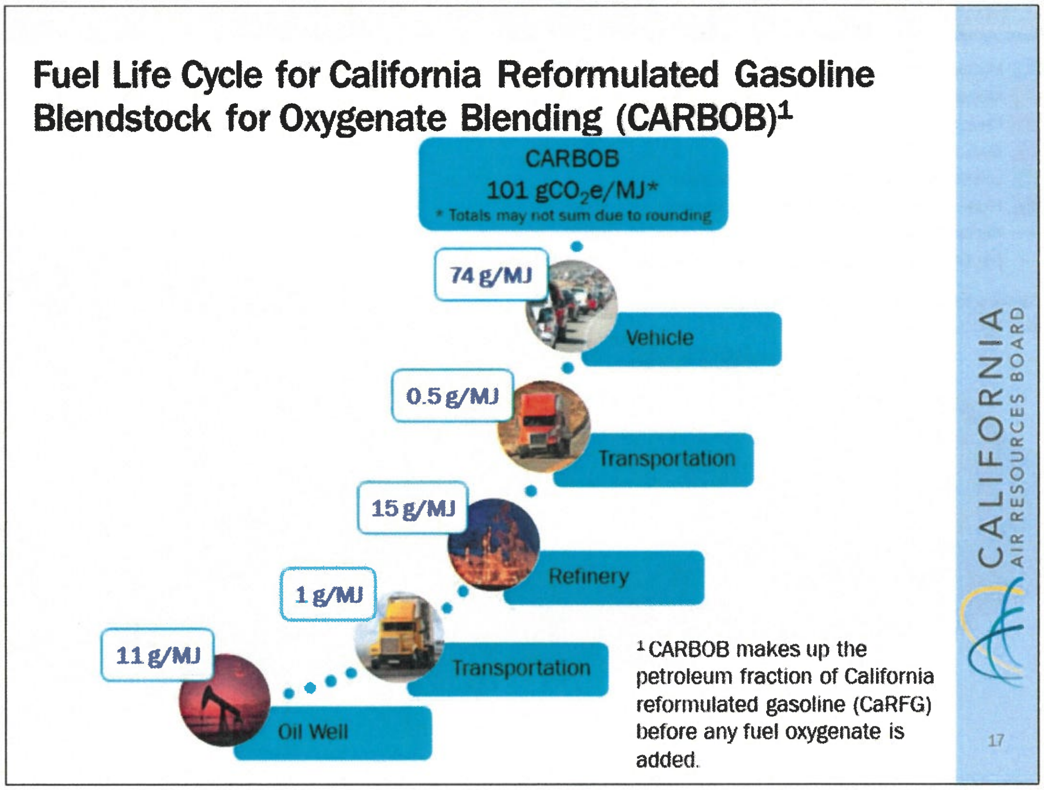
7) Carbon intensity of global crude oil refining and mitigation potential. Liang Jing et al. *Nature Climate Change* volume 10, pages 526–532 (J. Bergerson; 2020). The global-weighted carbon intensity at crude level is 10.1 – 72.1 kg CO2e/bbl, with a weighted average of 40.7 kgCO2e/kg.

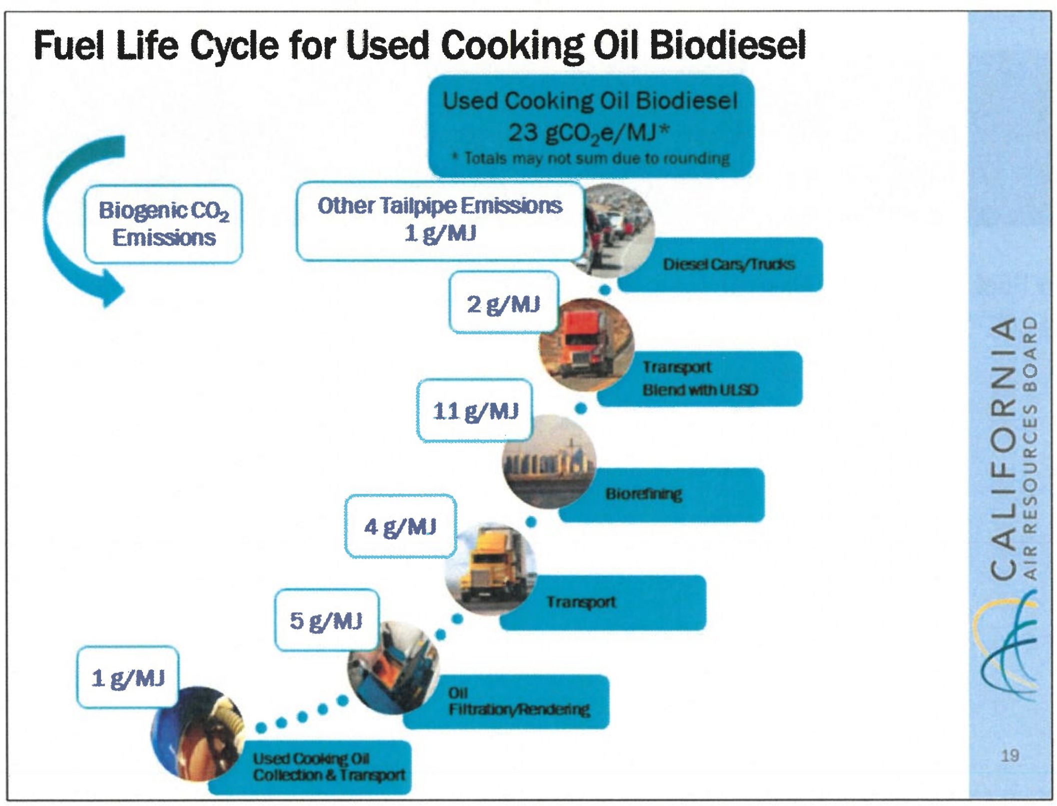


Nature

Carbon intensity of global crude oil refining and mitigation potential | Nature Climate Change

8) Low Carbon Fuel Standards. [Basics] <https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf>


Fuel Life Cycle for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)[1]
CARBOB
101 gCO_2e/MJ*
* Totals may not sum due to rounding
74 g/MJ
Vehicle
0.5 g/MJ
Transportation
15 g/MJ
Refinery
1 g/MJ
Transportation
11 g/MJ
Oil Well
[1] CARBOB makes up the petroleum fraction of California reformulated gasoline (CaRFG) before any fuel oxygenate is added.
CALIFORNIA AIR RESOURCES BOARD
17


Fuel Life Cycle for Used Cooking Oil Biodiesel
Used Cooking Oil Biodiesel
23 gCO_2e/MJ*
* Totals may not sum due to rounding
Biogenic CO_2 Emissions
Other Tailpipe Emissions
1 g/MJ
Diesel Cars/Trucks
2 g/MJ
Transport
Blend with ULSD
11 g/MJ
Biorefining
4 g/MJ
Transport
5 g/MJ
Oil Filtration/Rendering
1 g/MJ
Used Cooking Oil Collection & Transport
CALIFORNIA AIR RESOURCES BOARD
19

9) Cradle-to-Grave Lifecycle Analysis of U.S. Light-Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current (2015) and Future (2025-2030) Technologies Elgowainy A et al. Argonne National Laboratory ANL/ESD-16-7 Rev. 1. (September 2016) <https://publications.anl.gov/anlpubs/2016/09/130244.pdf>

10) Biodiesel. S Sadaka. (FSA1050: DIVISION OF AGRICULTURE RESEARCH & EXTENSION University of Arkansas System). < https://www.uaex.uada.edu/publications/PDF/FSA-1050.pdf>

11) Overcapacity Looms as More and More US Refiners Enter Renewable Diesel Market. Stratas Advisors. (June 11, 2020) https://stratasadvisors.com/Insights/2020/06112020LCFS-RD-Investment

12) Post-Rodeo Renewed Project Delayed Coker permit retention for possible re-use:

Weinberg-Lynn, Nikolas<Nik.Weinberg-Lynn@p66.com>
Fri 7/23/2021 3:31 PM

To:

- Charles Davidson

Cc:

- Ursino, Adrienne <Adrienne.Ursino@p66.com>;
- Henry, Aimee <Aimee.M.Henry@p66.com>

Mr. Davidson,
Thanks for your participation in the July 22nd RMAC meeting and questions about the Rodeo Renewed project related to the future use of the Coker. Phillips 66 is retaining the coker permit for a possible future evaluation of producing battery-grade coke at the Rodeo site. Battery-grade coke is a key component in the manufacture of electric vehicle batteries (see graphic below) and Phillips 66 is a major global supplier. Feedstock for the coker would be slurry oil, which would be sourced from a different refinery. Once the Rodeo Renewed project is fully implemented, the Rodeo facility will not be permitted to process crude oil. Emissions from a potentially operating Coker will be accounted for in the EIR.

I appreciate your interest in the project and look forward to further discussion,

Nik Weinberg-Lynn
Manager, Renewable Energy Projects
O: (+1) 510.245.4567 | M: (+1) 310.923.1436
RDO-RM 205 | 1380 San Pablo Avenue | Rodeo, CA 94572

13) Catalytic reforming options and practices. Tom Zhou (Fluor Enterprises)
Frederik Baars (Fluor BV). (2010). [Design and practice in catalytic reforming is evolving to

meet refinery challenges, including lower gasoline pool benzene content and increased demand for hydrogen.] https://www.digitalrefining.com/article/1000479/catalytic-reforming-options-and-practices#.Ym7Iji-B034

[redacted]

From: Maureen Brennan [redacted]
Sent: Monday, May 2, 2022 5:15 PM
To: Clerk of the Board
Subject: Public comment Phillips66 May 3 meeting

Please do not approve this land use permit for Phillips 66 at this time. At the Planning Commission endorsement, they said this permit should be in tandem with a Community Benefits Agreement. The details of any actual agreement have yet to be negotiated. Please table this item until details of the agreement are in place.

There are many details of the draft EIR still unanswered. The hydrogen plant has been ignored, nor addressed by the Planning Commission. The Air Liquide plant is not capable of the planned increase of methane-fuel consumption, which risks explosion, and at the least, increased flaring events. Air Liquide has a history of yearly “unit upset” since it went online in 2009. Investigation of the capability of this plant facility should be a condition for approval before the permit is granted.

Phillips 66 has claimed an “extensive odor remediation program” with no details. Details of the plan should be a condition for approval before the permit is granted.

Rodeo is classified as a disadvantaged community by Contra Costa County. SB1000 requires Contra Costa County to integrate environmental justice into its General Plan. We here in Rodeo and Crockett have long experienced a disproportionate burden of pollution and health impacts, noise and odors.

Please table the current proposal until these items are addressed.

Thank you.

Maureen Brennan

Rodeo, CA

[redacted]

From: Nlouise Wolfe <[redacted]
Sent: Monday, May 2, 2022 5:30 PM
To: Clerk of the Board
Subject: Reject Renewable Fuels Project's EIRs

Dear Contra Costa Supervisor,
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points,** especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough EIR.
I am a concerned California resident who is very worried about this precedent setting initiative.
Thank You,

Nanlouise Wolfe
Santa Cruz

[redacted]

From: Kathy Kerridge <[redacted]
Sent: Monday, May 2, 2022 5:57 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

Please reject the land use permits and require additional EIRs for the Phillips 66 and Marathon renewable projects.

The EIRs were inadequate in many ways. They failed to account for cumulative impacts even though these projects are happening at the same time literally miles from one another. They didn't address the impacts of essentially burning food for fuel. Especially now with the breadbasket of Europe under attack we do now want people across the globe to starve so we can drive cars that could be powered by electricity or hydrogen produced through using renewable energy. The climate impacts of this conversion could be devastating if soy oil users turn to palm oil and then more rainforest is destroyed to produce palm oil. If peat bogs are converted it would be a climate bomb. Indonesia recently stopped the export of palm oil because of the impact it was having on food prices.

Please say no. If the refineries can't tell us what percentage of their feed stock will come from used cooking oils, ect. as compared to oil grown instead of food, we can only assume the worst.

Kathy Kerridge

Benicia, CA

[redacted]

From: gailsusangordon [redacted]
Sent: Monday, May 2, 2022 7:42 PM
To: Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc: Clerk of the Board
Subject: Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's [Declaration of Climate Emergency] commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Gail Susan Gordon,
LMFT
San Pablo CA 94806

1000 Grandmothers for Future Generations

--

Gail Susan Gordon, LMFT, SEP

Licensed Marriage and Family Therapist

Somatic Experiencing Practitioner

1532 Solano Ave, Albany CA 94707

4980 Appian Way, Suite 206, El Sobrante CA 94806

gail@gailsusangordonmft.com

www.gailsusangordonmft.com

510-691-8123

[redacted]

From: Kathleen Rodgers [redacted]
Sent: Monday, May 2, 2022 7:48 PM
To: Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc: Clerk of the Board
Subject: Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Kathleen Rodgers, San Pablo
CA

[redacted]

From: Woody Hastings <[redacted]
Sent: Monday, May 2, 2022 7:56 PM
To: Clerk of the Board
Subject: Comments of The Climate Center - Agenda items D1 and D2, May 3, 2022
Attachments: The Climate Center FEIR Comment - 5-3-22.docx.pdf

Dear Clerk of the Board,
Please see attached letter from The Climate Center regarding agenda items D1 and D2 on the Board's May 3, 2022 agenda. If you have any difficulty opening the attachment, please let me know, and please share the comments with the Board.
Thank you,

Woody Hastings
Energy Program Manager, The Climate Center
310-968-2757 (mobile/text)

the climate center

Contact
www.theclimatecenter.org
P.O. Box 3785
Santa Rosa, CA 95402
707-525-1665

May 2, 2022

Contra Costa County Board of Supervisors
1025 Escobar Street, Martinez, CA 94553
Via Email: clerkoftheboard@cob.cccounty.us

Subject: Appeal of Contra Costa County Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project (File No. LP20-2040) and for the Marathon biofuel refining conversion project

Dear Contra Costa County Supervisors,

On behalf of The Climate Center and its supporters in Contra Costa County and throughout California, I urge you to reject the land use permit and require additional environmental reviews for Phillips 66 and Marathon refinery biofuel conversion projects. The Climate Center is a climate and energy policy nonprofit which works for rapid greenhouse gas (GHG) reductions, starting in California.

Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the concerns, especially those relating to safety and land use. The FEIRs inadequately address the following:

- Failure to consider climate impacts;
- Failure to comply with the CEQA requirement to respond to public comments;
- Failure to provide an adequate project description;
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen;
- Failure to account for impacts of burning food for fuel due to human food used as feedstock in biofuel refining;
- Failure to account for cumulative impacts.

Based on an analysis conducted by the Political Economy Research Institute in June 2021 "A Program for Economic Recovery and Clean Energy Transition in California," the transition to high road employment in the new clean energy economy can happen without extending the operation of these hazardous and polluting refineries. These refineries have also deleteriously impacted residents in nearby communities. A rejection by the Board of Supervisors to the proposals does not necessarily translate into lost jobs.

Lastly, Contra Costa County's [Declaration of Climate Emergency] commits to addressing the climate crisis in a way that protects the health and safety of vulnerable residents. To be consistent with the County's own climate emergency declaration, these projects demand a more thorough EIR.

Thank you for consideration of our concerns.

Sincerely,

Ellie M. Cohen
Chief Executive Officer
The Climate Center

[redacted]

From: Lisa argento martell [redacted]
Sent: Tuesday, May 3, 2022 4:30 AM
To: Clerk of the Board
Subject: Please reject the land use permit and EIR for renewable in Coco county!!

Dear Contra Costa Supervisors,
I am a concerned resident of Contra Costa county and live in Crockett.
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points,** especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. This whole project is replacing one dangerous and thoughtless industrial process with another. These projects demand a more thorough EIR.

Thank you for your attention and please forward my serious concerns.
Best regards,
Lisa Argento Martell
[redacted]
Crockett, CA 94525

[redacted]

From: lisa Sibony [redacted]
Sent: Tuesday, May 3, 2022 12:11 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects.

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents.These projects *must* have a more thorough EIR.

For the sake of the entire Bay Area, State of California and well beyond, please reject the permits and stop the refineries from causing more environmental damage.

Sincerely,
Lisa Sibony
Berkeley, CA

Contra Costa County

To: Board of Supervisors

From: John Kopchik, Director, Conservation & Development Department

Date: May 3, 2022

Subject: Appeal of the Phillips 66 Rodeo Renewed Project (County File# CDLP20-02040)

RECOMMENDATION(S):

1. OPEN the public hearing on an appeal of a Planning Commission decision to approve a land use permit for the Phillips 66 Rodeo Renewed Project at 1380 San Pablo Avenue in Rodeo and other project locations. (County File# CDLP20-02040), RECEIVE testimony, and CLOSE the public hearing.

2. CERTIFY that the Environmental Impact Report (EIR) for the Phillips 66 Rodeo Renewed Project (State Clearinghouse #20200120330) was completed in compliance with the California Environmental Quality Act (CEQA), was reviewed and considered by the County Planning Commission before project approval, and reflects the County's independent judgment and analysis.

3. CERTIFY the EIR prepared for the project.

4. ADOPT the CEQA findings for the project.

5. ADOPT the Mitigation Monitoring and Reporting Program for the project.

6. ADOPT the statement of overriding considerations for the project.

7. DIRECT the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk.

8. SPECIFY that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based.

9. DENY the appeal of Natural Resources Defense Council, et.al.; Charles Davidson; and the Crockett Community Foundation.

10. APPROVE the Phillips 66 Rodeo Renewed Project.

- [x] APPROVE
- [ ] OTHER
- [x] RECOMMENDATION OF CNTY ADMINISTRATOR
- [ ] RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** [x] APPROVED AS RECOMMENDED [ ] OTHER

Clerks Notes:

VOTE OF SUPERVISORS

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Contact: Gary Kupp

By: , Deputy

cc:

RECOMMENDATION(S): (CONT'D)

11. APPROVE the findings in support of project.

12 APPROVE the conditions of approval for the project.

13. APPROVE the attached Community Benefits Agreement.

FISCAL IMPACT:

The applicant has paid the necessary application deposit and is obligated to pay supplemental fees to recover any and all additional costs associated with the application process.

BACKGROUND:

Please find the Background section of this staff report in Attachment 1.

CONSEQUENCE OF NEGATIVE ACTION:

In the event the application is not approved, the applicant will not obtain the necessary permits to construct and implement the project.

CHILDREN'S IMPACT STATEMENT:

The project does not impact or affect any child-care programs in the County.

CLERK'S ADDENDUM

Speakers: Anne Alexander, Natural Resources Defense Council; Connie Cho, Citizens for a Better Environment;Greg Harris (Appellants); Charles Davidson (Appellant); Brian Montgomery, Crockett Commnity Foundation (Appellant); Richard Harbison, VP Phillips 66 Refinery (Applicant); Greg Feere, VP California Building Trades Council; Michael Cody, Rodeo; Tim Johnson, Schultz; Tyson Bagley, United Steelworkers Local 326; Gurant Murdock, Crockett Community Services District; Anthony Hodge, New Horizons; Janet Callaghan; Gary Hughes, Biofuelwatch; Janet Pyegeorge, Rodeo Citizens Association; Jan Warren, Interfaith Climate Action Network; Jesse Peralez, Local 152, Carbcutters 152; Jackie Garcia, 350 Contra Costa; Christine Cody, Rodeo; Michael Kirker, Director Rodeo Community Services District; Charles Miller, Superintendent, John Swett School District; Maureen Brennan, Rodeo; Teresa Foglio-Ramirez, Rodeo Shoshanna, Sunflower Alliance. Written commentary received is attached.

ADOPTED the recommendations with the addition of the following Conditions of Approval:

> **The owner/operator shall ensure that refinery doesn't exceed these limits: * cannot input more than 80,000 arrels of renewable feedstock per day, combined, based on a rolling 12 month period to the pretreatment unit * cannot process more than 67,000 bpd of renewable fuels**
>
> **To determine compliance with the above conditions, the owner/operator shall maintain the following records and provided all the data necessary to evaluate compliance, including but not necessaryl limited to, the following information: On a dailey baisis, type and amount of renewable feedstock processed.**
>
> These records shall be kept on-site for at least 5 years. all records shall be recorded in an BAAQMD approve log and made available for inspections by County staff upon requiest. Thes recordkeeping Requirements shall not replace the recordkeeping Requirements containe in any applicable BAAQMD Regulations.

Representative of Phillips 66 verbally confirmed agreement with the Community Benefit Agreement and the additional Conditions of Approval.

AGENDA ATTACHMENTS

Attachment 1 - Project Background & Appeal Responses

Attachment 2 - Project Findings & Conditions

Attachment 3 - Link to Environmental Impact Report

Attachment 4 - Community Benefits Agreement

Attachment 5 - NRDC Appeal Letter

Attachment 6 - Charles Davidson Appeal Letter

Attachment 7 - Crockett Community Foundation Appeal Letter

Attachment 8 - Mitigation Monitoring and Reporting

Attachment 9 - Maps and Site Plans

Attachment 10- Presentation

MINUTES ATTACHMENTS

Correspondence Received - 1

Correspondence Received - 2

Correspondence Received - 3

BACKGROUND SECTION OF MAY 3, 2022 STAFF REPORT REGARDING APPEAL OF THE PHILLIPS 66 RODEO RENEWED PROJECT (COUNTY FILE# CDLP20-02040)

INTRODUCTION

This is a hearing on an appeal of the County Planning Commission's March 30, 2022 decision to approve a Land Use Permit for the Phillips 66 Rodeo Renewed Project.

PROJECT SUMMARY

Phillips 66 proposes to modify the existing Rodeo Refinery into a repurposed facility that would process renewable feedstocks into renewable diesel fuel, renewable components for blending with other transportation fuels, and renewable fuel gas. Repurposing of the Rodeo Refinery would assist California in meeting its stated goals of reducing greenhouse gas emissions and ultimately transitioning to carbon neutrality. Under the project, up to 80,000 barrels per day (bpd), calculated over a 12-month rolling average, of renewable feedstocks could arrive at the Rodeo Refinery and would be processed in the proposed Pre-treatment Unit (PTU). The Refinery would supply up to 107,000 bpd of renewable and petroleum-based transportation fuels. The project would produce up to 55,000 bpd of a variety of renewable transportation fuels from renewable feedstocks. The Rodeo Refinery as a whole would produce up to 67,000 bpd of renewable fuels. To maintain the current facility capacity to supply regional market demand for transportation fuels, including renewable and conventional fuels, the Rodeo Refinery could receive, blend, and ship up to 40,000 bpd of gasoline and gasoline blendstocks.

GENERAL INFORMAITON

1. General Plan: Heavy Industry (HI).

2. Zoning: Heavy Industrial District (H-I).

3. California Environmental Quality Act (CEQA) Compliance: The Department of Conservation and Development, Community Development Division (CDD) determined that an EIR was required for the project and distributed a Notice of Preparation (NOP) on December 21, 2020.

   An Environmental Impact Report (EIR) was prepared and published for the project (State Clearinghouse #2020120330). The 60-day public review period for the Draft EIR started on October 18, 2021 and closed on December 17, 2021. During the comment period, the County received 86 comment letters on the Draft EIR and over 1,600 form letters both for and against the project. A Final EIR has been prepared that includes the comments received on the Draft EIR and the County's responses to those comments. The Final EIR also includes associated text changes relating to the comment responses. The Final EIR is included as an attachment to this report.

   Pursuant to CEQA Guidelines Sections 15091 and 15097, a Mitigation Monitoring Program has been prepared, based on the identified mitigatable significant impacts and mitigation measures in the project EIR. Additionally, the EIR identified significant and unavoidable effects for the project in the areas of Air Quality, Biological Resources, Hydrology/Water Quality, and Hazards/Hazardous Materials that cannot be fully mitigated to less-than-significant levels with implementation of identified mitigation measures; therefore, Public Resources Code section 21081(b) requires that the County make findings of overriding considerations to demonstrate that economic, legal, social, technological, or other benefits of the project outweigh the significant environmental effects of the project. Accordingly, the County has made the requisite findings of overriding consideration and has found that the potential benefits of the project do in fact outweigh the environmental impacts. The Statement of Overriding Considerations is included in the CEQA Findings attached to this report

4. Tribal Cultural Resources: As required by CEQA and Assembly Bill 52, Contra Costa County submitted a request for formal consultation to the Wilton Rancheria on October 21, 2020. Mariah Mayberry of the Wilton Rancheria responded on October 25, 2020, requesting consultation. Based on discussion between Contra Costa County and the Wilton Rancheria it was agreed that inclusion of four mitigation measures into the project EIR for the Project will satisfy the consultation requirements under AB 52.

SITE AND AREA DESCRIPTION

Project Sites:

1. Rodeo Refinery Site (1380 San Pablo Ave, Rodeo, CA 94572) - Refers to the 495-acre area within the Rodeo Refinery where the main project activities would occur.

2. Carbon Plant Site (2101 Franklin Canyon Rd, Rodeo, CA 94572) - Refers to the current location of the Carbon Plant in Franklin Canyon (within the 1,100-acre Rodeo Refinery).

3. Santa Maria Site (2555 Willow Rd, Arroyo Grande, CA 93420) - Refers to the Santa Maria Refinery, including the applicant-owned buffer land, located near Nipomo, San Luis Obispo County.

4. Pipeline Sites - Refers to four pipelines (i.e., Lines 100, 200, 300, and 400) that provide crude oil from the Santa Maria Site to the Rodeo Refinery.

The parcels in Contra Costa County that are part of the project site are Assessor Parcel Nos. 357-310-001, 358-010-008, 357-300-001, 357-300-008, 357-010-001, 357-320-002, 357-010-002, 358-020-004, 358-030-034, 357-300-005, 357-210-009, 357-210-010.

Area Description:

The Rodeo Refinery includes approximately 1,100 acres of land. The Rodeo Site, where the main components of the Project would take place, is the 495-acre developed portion of the property northwest of Interstate 80 (I-80). The Rodeo Site is currently covered by a mixture of impervious surfaces associated with process equipment, parking areas, roads, and other pervious surfaces. The remaining portion of the Rodeo Refinery, southeast of I-80, consists of a tank farm, the Carbon Plant Site, and undeveloped land that serves as a buffer zone. The Rodeo Refinery is bordered by San Pablo Bay on the north and west, open land to the east and southeast, the NuStar Energy tank farm on the northeast, the Bayo Vista residential area of Rodeo to the southwest, and the residential enclave of Tormey, located east and adjacent to the Nustar Energy tank farm. Originally constructed in 1896, at which time the land was essentially vacant and agricultural, the Rodeo Refinery occupied 22 acres. During the second half of the twentieth century, it was expanded considerably as capacity and new processes were added and as vacant buffer zone land was acquired. The areas adjacent to the Rodeo

Refinery are characterized by a mix of land uses including undeveloped land and industrial, commercial, office, and residential uses.

Directly abutting the Rodeo Site on the north is San Pablo Bay and the Union Pacific/Amtrak railroad right-of-way. Abutting the eastern boundary is the NuStar Energy tank farm, and beyond that a small residential enclave of Tormey along Old County Road and undeveloped, hilly open space. I-80 runs through the Rodeo Refinery roughly from southwest to northeast and divides the refinery portion of the property (i.e., the Rodeo Site) from the undeveloped portion of the property, part of the tank farm, and the Carbon Plant Site. San Pablo Avenue runs through the Rodeo Site in roughly the same direction as I-80 but is approximately 0.75 mile to the northwest.

To the south and west of the Rodeo Refinery, beyond a buffer zone of vacant land, is the Community of Rodeo. The enclave of Tormey and the Bayo Vista residential neighborhood of Rodeo, with several schools, at least one daycare center, several churches, and a few commercial establishments, are the closest residential area to the Rodeo Refinery. Because of the buffer zone, no residential or commercial uses directly abut the refinery. An apartment complex is located at the eastern edge of Bayo Vista. This complex comprises approximately 60 multi-unit buildings, the closest of which is approximately 400 feet from the refinery's border and is separated by the buffer zone space. All other residential uses are at least 0.25 mile (1,300 feet) from the refinery. No schools are within 0.5 mile (2,600 feet) of the Rodeo Refinery. The two closest schools are a Montessori academy on Parker Avenue (approximately 0.63 mile from the refinery) and the Rodeo Hills Elementary School on Rodeo Avenue (approximately 0.8 mile from the Refinery). Most commercial uses in the vicinity are located in an area centered on San Pablo Avenue/Parker Avenue, approximately 0.5 mile southwest of the refinery.

PROJECT DESCRIPTION

Phillips 66 proposes to modify the existing Rodeo Refinery into a repurposed facility that would process renewable feedstocks into renewable diesel fuel, renewable components for blending with other transportation fuels, and renewable fuel gas. Repurposing of the Rodeo Refinery would assist California in meeting its stated goals of reducing greenhouse gas emissions and ultimately transitioning to carbon neutrality. It would also provide a mechanism for compliance with California's Low-Carbon Fuel Standard and Cap and Trade programs and the federal Renewable Fuels Standard, while continuing to meet regional market demand for transportation fuels.

Once the project is in operation, no crude oil would be processed at the Rodeo Refinery. As the Rodeo Refinery transitions from a facility that refines petroleum feedstocks to one that processes renewable feedstocks, the refinery may (in order to maintain current production levels during the transitional period) temporarily increase deliveries of crude oil and gas oil feedstocks by tanker vessel, resulting in increased annual vessel calls to the Marine Terminal compared to baseline conditions. This temporary increase of crude and gas oil feedstocks at the Marine Terminal would not increase the amount of crude and gas oil that can be processed at the Rodeo Refinery, but it would shift the source of these materials from the Pipeline Sites to the Marine Terminal. The temporary or transitional increase in vessel traffic is estimated to last 7 months in the year prior to project startup, and would occur parallel to the end of the construction period. No modifications to the Marine Terminal or Marine Oil Terminal Engineering and Maintenance Standards Program are proposed.

Under the project, up to 80,000 barrels per day, calculated over a 12-month rolling average (bpd), of renewable feedstocks could arrive at the Rodeo Refinery and would be processed in the proposed Pre-treatment Unit (PTU). The majority of the time, the feedstocks treated by the PTU would be processed on site to produce renewable fuels. In situations where excess treated feedstock produced by the PTU is not processed onsite, this material could be exported from the Rodeo Refinery via the Marine Terminal. Marine traffic would increase relative to the baseline period. Marine traffic would include tanker vessels and barges used to import renewable feedstocks and gasoline blendstocks, and export renewable fuels and feeds. Baseline vessel traffic consists of 80 tankers of various sizes and 90 barges and is estimated to increase to a total of 201 Handymax tankers and 161 articulated tug barges at full project operation. No physical changes are needed at the Marine Terminal as part of the project.

Under the project, the Rodeo Refinery would supply up to 107,000 bpd of renewable and petroleum-based transportation fuels. The project would produce up to 55,000 bpd of a variety of renewable transportation fuels from renewable feedstocks. The Rodeo Refinery as a whole would produce up to 67,000 bpd of renewable fuels. To maintain the current facility capacity to supply regional market demand for transportation fuels, including renewable and conventional fuels, the Rodeo Refinery could receive, blend, and ship up to 40,000 bpd of gasoline and gasoline blendstocks.

ENVIRONMENTAL REVIEW

The County prepared an Environmental Impact Report (EIR) for the project (State Clearinghouse# 2020120330). The project EIR is composed of both a Draft EIR and Final EIR. The Notice of Preparation (NOP) of the EIR was posted on December 21, 2020 and a public Scoping Meeting was held on January 20, 2021. Both written and oral comments were received during the NOP public comment period and the Scoping Meeting; the comments were responded to in the Draft EIR, which was released for public review on October 14, 2021 with a Notice of Availability. A 60-day comment period for the Draft EIR began on October 18, 2021 through December 17, 2021. During the comment period, the County received 86 comment letters on the Draft EIR and over 1,600 form letters both for and against the project. The comment topics included concerns about refinery emissions, hazardous materials, land use relating to renewable feedstock crops, and public safety. The County's Reponses to the comments received are provided in the Final EIR that has been prepared for certification by the County Board of Supervisors.

The EIR for the proposed project identified significant and unavoidable effects for the project in the areas of Air Quality, Biological Resources, Hydrology/Water Quality, and Hazards/Hazardous Materials:

1. Rail transport outside the San Francisco Bay Area Air Basin would expose sensitive receptors to substantial pollutant concentrations, resulting in a significant impact for the project.

2. The effects of vessel cargo loading/offloading (accidental oil spills) and the introduction of nonindigenous invasive species would have a substantial adverse effect on Biological Resources, resulting in a significant impact for the project.

3. The effects of vessel cargo loading/offloading (accidental oil spills) would have a substantial adverse effect on Hydrology/Water Quality, resulting in a significant impact for the project.

4. The effects of vessel cargo loading/offloading (accidental oil spills) would have a substantial adverse effect due to Hazardous Materials, resulting in a significant impact for the project.

When a public agency determines that a project will have significant and unavoidable effects, Public Resources Code section 21081 provides that the public agency may approve the project if it finds that economic, legal, social, technological, or other considerations, including provision of employment opportunities for highly trained workers, make imposition of mitigation measures or Project alternatives infeasible. The agency must also adopt statement of overriding considerations that economic, legal, social, technological, or other benefits of the project outweigh the significant environmental effects of the project. The County can make the requisite findings and adopt the statement of overriding consideration that the potential benefits of the project do in fact outweigh the environmental impacts. The project's benefits include:- A just transition process that will preserve the existing work force.

- The Rodeo refinery would no longer process crude oil for petroleum-based fuels.
- The project would assist California in meeting goals of reducing greenhouse gas emissions and ultimately transitioning to carbon neutrality.
- The project would also provide a mechanism for complying with California's Low-Carbon Fuel Standard and the Federal Renewable Fuels Standard, while continuing to meet regional market demand for transportation fuels.
- The project would reduce emissions of air pollutants relative to existing conditions.

The County's findings and statement of overriding consideration are attached to this staff report in the project's findings and proposed conditions of approval.

In addition, other potentially significant impacts were also identified, all of which can be mitigated to a less-than-significant level. These impacts affect the environmental topics of:

- air quality,
- biological resources,
- cultural & tribal cultural resources,
- geology and soils, and
- transportation & traffic.

Environmental analysis contained in the EIR determined that measures were available to mitigate these potential adverse impacts to less-than-significant levels.

A Final EIR has been prepared that includes the written comments received on the Draft EIR and the County's responses to the comments received. The Final EIR also includes County-initiated updates and errata to the Draft EIR. These errata constitute minor text changes to the Draft EIR in the sections relating to the Executive Summary, Project Description, Air Quality, Biological Resources, Cultural Resources, Geology & Soils, Greenhouse Gas Emissions, Hazards/Hazardous Materials, Hydrology & Water Quality, Tribal Cultural Resources, Alternatives Analysis, Cumulative Impacts, and Appendix B. The changes were made primarily to correct grammatical and typographical errors, as well as to improve accuracy and readability of certain passages. The text changes are not the result of any new significant adverse environmental impact, and do not alter the effectiveness of any mitigation included in the pertinent section, and do not alter any findings in the Draft EIR. Pursuant to CEQA Guidelines Section 15088.5(a), recirculation of a Draft EIR is required only if:

"1. a new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented;

2. a substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance;

3. a feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it; or

4. the draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded."

None of the text edits or changes to the Draft EIR meet any of the above conditions. Therefore, recirculation of any part of the Draft EIR is not required. The information presented in the project EIR support this determination by the County.

Pursuant to CEQA Guidelines Sections 15091 and 15097, a Mitigation Monitoring Program has been prepared, based on the identified significant impacts and mitigation measures in the project EIR. The Mitigation Monitoring Program is intended to ensure that the mitigation measures identified in the EIR are implemented. The Mitigation Monitoring Program is included herein (Exhibit 4). All mitigation measures are included in the Conditions of Approval.

STAFF ANALYSIS

1. General Plan Consistency

The majority of the Rodeo refinery is designated Heavy Industry (HI). The HI designation allows activities such as oil refining and other manufacturing operations requiring large areas of land with convenient truck and rail access. The following standards apply to the Heavy Industry designation:

• Maximum site coverage: 30%

• Maximum floor area ratio: 0.67

• Average employees per gross acre: 45 employees

The Rodeo Renewed Project does not conflict with the overall goals, standards, and policies of the General Plan because it is consistent with the Heavy Industry land use designation for the site; and is consistent with the Growth Management Performance Standards.

Noise Element:

The Noise Element sets various goals and policies that apply to all development projects in the county. Most of these policies address land use compatibility for evaluating the acceptability of existing and future exterior noise levels for new projects, such as commercial and residential developments, and for proposing noise-sensitive receptors; thus, they are not directly applicable to the project, which is in an existing industrial zone. Notwithstanding, Noise Element Policy 11-8 is applicable to the project.

Policy 11-8. Construction activities shall be concentrated during the hours of the day that are not noise-sensitive for adjacent land uses and should be commissioned to occur during normal work hours of the day to provide relative quiet during the more sensitive evening and early morning periods.

Project demolition and construction activities would be conducted during daytime or normal working hours on industrial-zoned land. Project operational noise from mechanical equipment would not be substantially different than existing noise emanating from equipment presently in use at the project site.

The environmental impact report (EIR) analyzed the proposed project for its impacts relating to noise associated with day-to-day operation of the refinery, temporary construction and demolition activities, and ground-borne vibration. The EIR analysis found that noise impacts under the proposed project will be less than significant; therefore, the project does not conflict with the appliable goals and policies of the Noise Element.

Transportation and Circulation Element:

The Transportation and Circulation Element includes the following policies that are applicable to the proposed project:

Policy 5-4. Development shall be allowed only when transportation performance criteria are met and necessary facilities and/or programs are in place or committed to the developed within a specified period of time.

Policy 5-14. Physical conflicts between pedestrians, bicyclists, and vehicular traffic shall be minimized.

Policy 5-17. Emergency response vehicles shall be accommodated in development of project design.

The Transportation and Circulation Element of the General Plan shows designated arterials and expressways that are part of the County roadway network. San Pablo/Parker Avenue is designated as an arterial roadway in the General Plan and as a route of regional significance by the Contra Costa Transit Authority. San Pablo Avenue is a four-lane arterial that provides north-south access in the project vicinity and runs through the refinery site. San Pablo Avenue connects with Interstate I-80 via the Cummings Skyway interchange north of the refinery and in Crockett. The speed limit on San Pablo Avenue in the vicinity of the Rodeo Site is 45 mph. Parker Avenue is a two-lane divided roadway that connects San Pablo Avenue to Willow Avenue, providing access to the Willow Avenue interchange with I-80 to the south of the refinery site. The speed limit on Parker Avenue is 30 mph. Contra Costa County currently has plans for a road improvement project on San Pablo Avenue between Rodeo and Crockett, adjacent to the Rodeo refinery. Phillips 66 is not proposing modifications to existing Rodeo refinery access points.

Day-To-Day Operations. The project EIR found that operation and maintenance of the project would not result in increased traffic on any roadway segments currently being used by pedestrian, bicycle, or transit facilities in the area, and the use of these existing facilities would not increase because project operation would be accommodated with the existing workforce. Employee traffic would not change with implementation of the proposed project. With the demolition of the Carbon Plant, truck traffic related to the transport of petroleum coke to and from the Carbon Plant site, which totaled 32,673 round trips in 2019, would no longer occur. As a result, annual truck round trips under the project would decrease to approximately 16,026 truck roundtrips per year. Therefore, operation and maintenance of the project would not result in a conflict with a plan, ordinance, or policy establishing measures of effectiveness for the performance of the circulation system, including transit, roadway, bicycle, and pedestrian facilities.

Construction and Demolition. The project would result in increased truck and employee traffic to and from the Rodeo site and the Carbon Plant during the construction/demolition phase of the project. Materials such as concrete, structural steel, pipe and fittings, vessels and associated equipment, electrical equipment, insulation and construction services equipment (e.g., portable toilets, temporary office trailers for construction contractors) would be delivered by truck. Asphalt, steel, and concrete generated by demolition and site preparation activities would be transported off site by truck. These traffic increases would be temporary and would cease upon completion of the construction and demolition activities. Furthermore, with implementation of an approved Traffic Management Plan, potential traffic impacts associated with all phases of construction and demolition of the project would be less than significant.

Rail Traffic. The Rodeo refinery is served by two rail lines: the Union Pacific/Amtrak mainline passing through the Rodeo site along the shoreline and the Burlington Northern-Santa Fe mainline passing by the Carbon Plant site through Franklin Canyon. The Union Pacific line supports daily service to the Rodeo site to handle approximately five butane railcars per day at a rail loading facility adjacent to the mainline tracks. The Burlington Northern-Santa Fe line supports a thrice-weekly service handling an average of seven petroleum coke railcars per week (a little more than two per visit on average). Rail traffic would be altered by the project, but the effects would result in a reduction in rail cars overall.

Emergency Access. Multiple roadways provide external access to the Rodeo site, and internal roadways within the Rodeo refinery also provide access for both general and emergency vehicles. These access points include several temporary/emergency vehicle access entrances on San Pablo Avenue, in addition to the main signalized entrance intersection with Refinery Road.

Safety Element: The Safety Element of the General Plan contains relevant goals and policies regarding hazardous materials and fire protection. The hazardous materials goal is to provide public protection from hazards associated with the use, transport, treatment and disposal of hazardous substances and is supported by policies that require appropriate storage and containment of hazardous substances. Fire protection goals are intended to provide public protection services in a disaster. The project will be replacing petroleum feedstocks that are regulated as hazardous materials with renewable feedstocks which are not categorized as hazardous materials, and therefore conforms to the goals and policies of the Safety Element.

2. Zoning Consistency

The majority of the Rodeo refinery, including the locations of all proposed project units and modifications, is zoned Heavy Industrial District (H-I), which allows heavy industrial manufacturing uses of all kinds, including, but not limited to, lumber, steel, chemicals, explosives, fertilizers, gas, rubber, paper, cement, sugar, and all other industrial or manufacturing products including the processing of petroleum and the manufacturing of petroleum products (i.e. crude oil refining). Renewable fuels processing and refining is considered a permitted use in the H-I District, but a land use permit is required for this project because of the change in use of the facility from a petroleum refining facility to one that processes renewable feedstocks. As proposed, the project is consistent with the H-I zoning district.

3. Development Standards

The Heavy Industrial zoning district requires a 10-foot setback from any property line fronting on a roadway. The project conforms to this standards.

4. County Hazardous Materials Programs

The Contra Costa County Health Services Department oversees the hazardous materials regulatory programs relating to aboveground storage tanks, underground storage tanks, hazardous waste generators, Hazardous Materials Business Plans (HMBP), as well as facility inspections and permitting related to CalARP.

Contra Costa County has adopted the Contra Costa County Hazardous Materials Area Plan, which outlines the procedures that county regulatory and response agencies will use to coordinate management, monitoring, containment, and removal of hazardous materials in the event of an accidental release. The purpose of the HMBP Program is to prevent or minimize the damage to public health and safety and the environment from a release or threatened release of hazardous materials and also to satisfy community right-to-know laws. The program requires facilities that handle hazardous materials in quantities equal to or greater than 55 gallons of a liquid, 500 pounds of a solid, 200 cubic feet of compressed gas, or extremely hazardous substances above the threshold planning quantity to prepare and submit a HMBP that contains:

- A hazardous materials inventory,
- Site maps,
- Emergency Response Contingency Plans, and
- Employee Training Plan.

The County verifies the information included in the HMBP and provides it to agencies responsible for the protection of public health and safety and the environment. These agencies may include fire departments, hazardous materials response teams, and local environmental regulatory groups. Businesses must amend the HMBP and submit to Contra Costa Health Services, Hazardous Materials Programs, within 30 days if there is:

- A 100 percent or more increase in the quantity of the previously disclosed amount,
- Any handling of a previously undisclosed hazardous material in a reportable quantity,
- A change of business address,
- A change of business ownership,
- A change of business name, or
- A significant change in business operations affecting handling of hazardous materials.

The project will comply with the requirements of the Contra Costa Hazardous Materials Programs.

5. Stormwater Management and Discharge Control

The Contra Costa Clean Water Program is responsible for coordinating compliance with Municipal Separate Storm Sewer System (MS4) National Pollutant Discharge Elimination System (NPDES) permits for jurisdictions throughout Contra Costa County. The program is conducted in compliance with the NPDES Municipal Regional Permit issued by the San Francisco Bay Francisco Bay Regional Water Quality Control Board (RWQCB). The permit contains a comprehensive plan to reduce the discharge of pollutants to the “maximum extent practicable” and mandated that participating municipalities implement an approved stormwater management plan. The program incorporates Best Management Practices (BMPs) that include construction controls (such as a model grading ordinance), legal and regulatory approaches (such as stormwater ordinances), public education and industrial outreach (to encourage the reduction of pollutants at various sources), inspection activities, wet-weather monitoring, and special studies.

Under the MS4 NPDES Municipal Regional Permit issued by the San Francisco Bay RWQCB, Contra Costa County requires construction sites to have site specific and seasonally BMPs in the following five categories: erosion control; run-on and runoff control; sediment control, active treatment systems; good site management; and non-stormwater management. The permit contains a comprehensive plan to reduce the discharge of pollutants to the “maximum extent practicable” and mandates that participating municipalities implement an approved stormwater management plan. The plan incorporates BMPs that include construction controls, permanent stormwater management (treatment and flow control) facilities to manage runoff from new development and redevelopment projects, legal and regulatory approaches (such as stormwater ordinances), public education and industrial outreach (to encourage the reduction of pollutants at various sources), inspection activities, wet-weather monitoring, and special studies. The project area is regulated by the Rodeo Refinery’s NPDES permit, which is in compliance with the County’s MS4 NPDES permit with specific requirements for development and implementation of a Storm Water Pollution Prevention Program (SWPPP).

Stormwater falling on the Rodeo Refinery and adjacent areas, including internal roadways, is collected onsite and conveyed through a drainage network to the onsite Wastewater Treatment Plant (Unit 100). The collection network includes screens to separate out trash and settling sumps to initiate clarification. Normally, stormwater is conveyed directly to the Unit 100 storage tanks, but heavy rains can result in capacity exceedance, necessitating the diversion of stormwater to holding basins before being treated and released. The primary storm basin holds 2.3 million gallons, and the main storm basin holds an additional 7.2 million gallons; these basins are empty under normal operation. Stormwater from the Marine Terminal wharf and causeway is routed to NPDES discharge outfall on the wharf structure. The existing SWPPP establishes a monitoring program to confirm the effectiveness of the BMPs and overall stormwater quality, which is routinely monitored as part of NPDES permit requirements. The Rodeo Refinery is not covered by a separate industrial stormwater permit because rain and runoff from operation areas are collected, treated, and discharged under the NPDES permit.

APPEAL OF THE PLANNING COMMISSION'S DECISION

A Land Use Permit for the applicant’s project was approved by the County Planning Commission on March 30, 2022. Public testimony was taken for and against the project. Commenters raised a list of concerns including adequacy of the project description, accuracy of the baseline evaluation, adequacy of the hazard analysis related to hydrogen, adequacy of food-system-impact review, job creation impacts, emissions impacts, and other issues, both positive and negative, regarding the project implementation. The Commission voted 6-0 to certify the Project environmental impact report and approve the land use permit application.

Subsequently, during the 10-day appeal period, three separate appeals were filed by the following parties:

1) Natural Resources Defense Council (NRDC), et.al. (consisting of Biofuelwatch; California Environmental Justice Alliance; Center For Biological Diversity; Communities for a Better Environment; Richmond City Council members 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; Rodeo Citizens Association; San Francisco Baykeeper; Stand.Earth; Sunflower Alliance; The Climate Center; and 350 Contra Costa County).

2) Mr. Charles Davidson.

3) Crockett Community Foundation.

Staff has prepared the following responses to each of the appeals.

NRDC et. al. Appeal

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

Section I of the Appeal presented by the NRDC, et al, asserts that the decision to certify the EIR is contrary to law and not supported by substantial evidence, and that the EIR fails to meet the requirements of CEQA in the following areas:

- Project Description
- CEQA Baseline
- Hazards from increased operational upsets
- Global food system oil consumption
- Deferment of odor mitigation
- Cumulative impacts
- Climate pathways
- Transportation risk impacts

Appellants assert that the County failed to adequately respond to comments received on the Notice of Preparation and the Draft EIR regarding these issues. Each of these points is responded summarized below followed by staff's responses.

Appeal Subpoint (a) "Failure to provide an adequate project description."

The Appellants contend the Draft EIR provided "essentially no information" regarding the type of process technology (Hydrotreating Esters and Fatty Acids [HEFA]) proposed by the Project that is to be used at an unprecedented scale. They contend that lack of this information renders the project description in adequate and thus fails to meet the standards of CEQA, particularly referencing the "undisclosed bottlenecking" issue raised in comments on the Draft EIR that were only partially addressed in the Final EIR.

Staff Response

The document thoroughly discusses applicable processing technologies pertaining to the types of renewable feedstocks proposed to be refined at the Rodeo facility. Draft EIR Chapter 3, Project Description (Sections 3.5 through 3.9), and Final EIR Master Response No. 5, Renewable Fuels Processing, which provides supporting technical background information, specifically address the Project's process technology. Specifically, the key components of the proposed renewable fuels processing – the use of hydrotreaters, the use of hydrogen, and the use of vegetable oils or animal fats – are described in the EIR. The proposed process is depicted in Figure 3-7 of the Project Description, which includes the Hydrotreater Units 240 and 246. Section 3.8.2, Anticipated Project Feedstocks, describes the various feedstocks to be utilized, including used cooking oils (UCO), fats, oil and grease (FOG), vegetable-based oils, including inedible corn oil, canola oil soybean oil and tallow. Section 3.9.1.1, Reconfiguration of Process Units for Renewable Feedstock Processing, lists Units 240 and 246, each identified as a Hydrocracker, along with the existing Hydrogen Plant.
Regarding the issue of "debottlenecking", a bottleneck implies that the Project has the capacity to produce more renewable fuels if it only had more hydrogen. Appellants assert that the Applicant intends to relieve this bottleneck by producing additional hydrogen to produce more renewable fuels than reported in the Draft EIR.

Hydrogen capacity at the Rodeo Refinery is limited by the existing Hydrogen Plant (Unit 110) and Air Liquide's facility, which is a third-party supplier of hydrogen to the Rodeo Refinery. The Project does not propose to produce additional hydrogen. However, the Draft EIR acknowledges that the Project has the potential to indirectly increase the use of hydrogen that would be supplied by Air Liquide, but also states that this potential increase would not require Air Liquide to modify its operations. Information contained in revised Draft EIR Appendix B, Air Quality and Greenhouse Gas Emissions Technical Data is summarized below to show the amount of hydrogen production at baseline and post-Project.

Rodeo Refinery Hydrogen Production (Unit 110)
Baseline: 12 million standard cubic feet (scf)/day
Post Project: 22 million scf/day

Air Liquide Hydrogen Production
Baseline: 93.26 million scf/day
Post Project: 120 million scf/day

Baseline vs. Project Totals
Total Baseline: 105.26 scf/day
Total Post Project: 142 scf/day

Thus, Total additional hydrogen required by the project = 36.74 million scf/day.

As indicated above, at maximum operating limits the Project would require an additional 36.74 million scf/day or approximately 35 percent more hydrogen above baseline conditions. For the purposes of CEQA and as cited above, the EIR assumes the maximum existing production capacities to provide a reasonable worst-case analysis for hydrogen use. However, it is not expected that the Project would require the maximum available hydrogen primarily due to fluctuating feedstock supply and demand; the amount of hydrogen needed for the renewable fuels process is based on the type and mixture of feedstock being processed.

The Draft EIR includes the 35 percent increase in hydrogen use in the air emissions modeling. Even though the hydrogen use per barrel of feed may increase, the processing units will process fewer barrels of renewable feedstocks as compared to crude oil feedstocks, and the overall hydrogen usage per processing unit is within this historic range of the Rodeo Refinery. Accordingly, hydrogen demand of a renewable diesel hydrotreater (or hydroprocesser) is similar to that of existing process units at Rodeo Refinery. Impacts related to the increased use of hydrogen are found to be less than significant. Therefore, the Draft EIR does not dismiss the increase in hydrogen use and the Project would not produce more renewable fuels than reported in the Draft EIR.

It should be noted an EIR is to be "written in plain language and may use appropriate graphics so that decision makers and the public can rapidly understand the documents" (CEQA Guidelines, Section 15140). The Draft EIR provides sufficient information to evaluate the environmental effects of the proposed processing method for renewable fuels, including the use of hydrogen. Therefore, the Project Description is adequate under CEQA Guidelines 15124(c).

Appeal Subpoint (b) "Improper baseline."

The Appellants contend that the Project baseline is inaccurate and thus skews all analysis in the Draft EIR. Specifically, Appellants state that the baseline is "inconsistent with available facts, which demonstrate severe and increasing constraints on the Refinery's access to crude feedstock", implying that the baseline should assume no or a "diminished" throughput.

<u>Staff Response</u>

County staff considers a "no operation" or diminished operational baseline as inappropriate since it relies on a hypothetical future scenario presented by the Appellants rather than actual facility emissions. The Appellant's baseline is based on a "future scenario" under which neither the Rodeo Refinery nor the Santa Maria Refinery exist due to no or low supply of crude or semi-refined crude. To require analysis of such a hypothetical future baseline is inconsistent with the requirements of CEQA and would misinform the public and decision makers since, as determined by County staff, it is a scenario that would not happen. Final EIR Master Response No. 1, Baseline provides detail and evidence to support that determination.

CEQA Guidelines require that the baseline is the point in time or the set of conditions against which expected future environmental conditions associated with the Project are compared. Changes in the baseline environmental conditions resulting from a project represent the project impacts that must be disclosed under CEQA. Therefore, definition of an appropriate baseline is an integral part of the CEQA process. Section 15125 of the CEQA Guidelines provides the following direction for establishing the baseline:

"An EIR must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, from both a local and regional perspective.

This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant."

The baseline year is typically selected as the year in which the Notice of Preparation ("NOP") is released for a proposed project. However, the lead agency has the discretion to select a more appropriate baseline year for purposes of the environmental analysis conducted in the EIR if conditions warrant such a selection. The NOP for the Project was released in 2020 but, as described in the Draft EIR, 2020 was not an appropriate year for the Project baseline because of the Covid 19 pandemic and the Refinery's compliance with BAAQMD Regulation 9 Rule 14 that went into effect on January 1, 2019, which requires the owner/operator of a petroleum coke calcining operation to comply with the following sulfur reduction regulations:

— To operate all Petroleum Coke Calcining Kilns such that the SO2 emissions from all kilns combined do not exceed 320 pounds per hour, averaged over any consecutive 24 hours.

— To operate all Petroleum Coke Calcining Kilns such that the SO2 emissions from all kilns combined do not exceed 1,050 tons per year on a twelve-month rolling average basis.

Further, the Refinery would continue to operate without the Project contrary to the documentation provided by the Appellants. The Applicant has not stated or indicated otherwise to County staff.

As addressed in Final EIR Master Response No. 1, CEQA Baseline, if the supply of crude or semi-refined crude became severely constrained, the Applicant would procure it by other means as has been historically done to accommodate the fluctuating crude oil market. The Draft EIR acknowledges that the crude oil market fluctuates, but County staff does not believe, based on the supporting documentation presented in the Final EIR, that the supply of crude oil is expected to substantially decrease or become completely unavailable to the point that the Applicant would have no choice but to shut down the Rodeo Refinery and Santa Maria Refinery.

Appeal Subpoint (c) "Failure to account for potentially increased operational upsets."
The Appellants contend that HEFA biofuel processing can lead to increased process upsets.

Staff Response

As addressed in Draft EIR Section 4.9, Hazards and Hazardous Materials, and Final EIR Master Response No. 5, Renewable Fuels Processing, which provides supporting technical background information, the Project does not have an increased risk of hazards from the processing of renewable feedstocks. The causal events for upset conditions in hydrotreating would be the same for HEFA and petroleum. Those events include loss of cooling, loss of power, loss of feed, and loss of hydrogen. As detailed in Final EIR Master Response No. 5, the process of hydrotreating of fats, oils, and greases (all renewable feedstocks) to renewable diesel is completed at temperatures and pressures similar to existing petroleum processing steps. Because the operating conditions are so similar, the risk of a causal event that would result in a process upset would be the same for HEFA and petroleum. In response to claims that renewable feedstocks could "gum or plug process flows," Master Response No. 5 provided further information regarding the PTU. Again, renewable fuels processing is very similar to crude oil processing and "the purported increase in hazards described by comments is not supported by the science." (Master Response No. 5, p. 3-46.) As a result, the EIR concludes that the transition from petroleum processing to HEFA would not result in more or additional process upsets.

In addition, as described in Section 4.9, hydrogen processing units, regardless of feedstock, must be evaluated for process safety risks. A principal purpose of process safety is to reduce the magnitude of incidents, thereby reducing the harm to people and the environment. All refinery design changes undergo review by qualified engineering professionals, and when County permits are required, the changes will undergo review by County engineering and hazmat staff. These review efforts ensure the proposed design meets industry process safety management requirements and acceptable level of risk.

Flaring. Flares are essential safety devices used at the Rodeo Refinery to burn hydrocarbon gases that cannot be recovered or recycled. Refineries are designed and operated so that there is a balance between the rates of gas production and consumption. Flares are used to safely combust the excess, rather than release hydrocarbon to the atmosphere. With implementation of the Project, the amount of flaring would not increase, and there would be no change to the flare gas recovery compressors number or use. Phillips 66 proposes no physical changes to its flare system and will continue to operate they system under current regulatory requirements. Regardless, the Refinery, as it exists now and as a post-project facility processing renewable fuels, is strictly regulated by the BAAQMD, including Regulation 12, Rule 11: Flare Monitoring at Refineries and Regulation 12, Rule 12: Flares at Refineries, including BAAQMD Regulation 12-12404. In addition, the Rodeo facility's BAAQMD Major Facility Review Permit includes conditions for flaring which will continue to apply with the Rodeo Renewed Project. Therefore, project process hazards and flaring operations impacts will be similar to, or reduced, as compared to petroleum processing operations.

Appeal Subpoint (d) "Failure to account for impact of massive food system oil consumption."
The Appellants contend they have provided extensive documentation of the environmental impacts risks from the "massive disruption in the food system" that the Project would create, especially the risk that soybean oil demand and associated price spikes will incentivize production of palm oil and associated deforestation.

Staff Response

The Final EIR Chapter 3, Section 3.2, Master Response 4: Land Use and Feedstocks, pp. 3-29 to 3.37, addresses Draft EIR comments on the LCFS program, indirect land use impacts, and feedstock sources and mixes. As discussed in Section 3.8 of the Draft EIR, the Applicant proposes use of a variety of feedstocks (used cooking oil, fats and greases, animal fat, inedible corn oil, canola oil, other vegetable-based oils, including soybean oil). The precise types, sources and amounts of feedstocks are unknown due to the many layers of highly variable inputs (highly variable market conditions, individual government regulations and incentives can be different), and therefore, the Project's effect on the food system is speculative.

The EIR discusses these issues in the Draft EIR Chapter 3, Project Description, Section 3.8, Project Renewable Feedstocks, and Master Response No. 4, Land Use and Feedstocks. It is not proposed or expected that the Applicant would rely on a single renewable feedstock, such as soybean oil. To address fluctuating markets, the Applicant has stated it currently secures contracts in excess of the crude oil feedstocks supply needed to process the more than 2 million barrels of crude oil per day. The Applicant's position in the market is then adjusted as needed over time, depending on the market conditions for that year or month (or appropriate time interval); it would be similar for the procurement of renewable feedstocks. The Applicant could secure market positions in oilseeds, vegetable oils, and waste oils, and by having an excess of the amounts needed for processing, the Applicant has the flexibility to adapt to market conditions and process the optimal mix of renewable feedstocks to achieve maximum low carbon credits and meet its business objectives.

In addition, the Rodeo Refinery is uniquely situated to secure renewable feedstocks available through marine shipping by having direct marine access through the Marine Terminal in addition to rail and truck transportation. By having these transportation options, the Applicant has greater flexibility in selecting renewable feedstocks from a broad variety of sources, including international sources.

For the reasons above, the Project will have the ability to process a broad range of untreated renewable feedstocks. Whether the selection looks more or less favorably on any particular renewable feedstock to process at the Rodeo Refinery in 2024 and beyond will depend on all of the factors that comprise the costs, transportation logistics, and carbon intensity associated with that particular feedstock. To assume the majority of feedstock would be soybean oil or any other single feedstock is not realistic. It is also not reasonable or expected under CEQA to assume an extreme or maximum worst case scenario, such as soybean oil being the primary feedstock, in order to evaluate the impacts of the Project.

As addressed in Final EIR Master Response No. 3, Cumulative Impacts, like the Project's own individual feedstock-related impacts, the contribution to indirect global impacts of the Project's feedstock use is speculative and unable to be quantified. Irrespective of the market-based projections that may or may not be available for other projects, this Project's feedstock mixes and sources cannot be predicted at this time without speculation (refer to Master Response No. 4, Land Use and Feedstocks). In turn, because the identities and availability of the Project's feedstocks cannot be determined at this time, the County cannot reasonably evaluate the Project's global impacts related to these inputs beyond the information provided in the Draft EIR. Assessment of the Project's incremental contribution to cumulative impacts related to feedstocks would necessarily involve several layers of speculation. Because speculation precludes assessment of this Project's own feedstock cultivation impacts, it is unknowable whether the Project's feedstock demands will have an adverse environmental impact at all, let alone one that is cumulatively considerable.

CEQA Guidelines state that an EIR's discussion of cumulative, or global indirect, impacts should be guided by the standards of practicality and reasonableness. Addressing the global implications of the Project is beyond the scope of CEQA – which is a state statute not intended to address nationwide or worldwide implications of an individual project.

Appeal Subpoint (e) "Improper deferment of odor mitigation plan."

The Appellant contends that the formulation of mitigation measures, specifically the Odor Management Plan, cannot be deferred until after the CEQA process and cannot be completed only "prior to operation of the Project". The Appellants argue that the EIR improperly delayed addressing potential odors from the project "whose impacts may be considerable depending on what feedstocks are used." The Appellants further state that this deferral is prohibited by CEQA (Guidelines § 15126.4(a)(1)(B)) since "the point of CEQA is to disclose and allow the public to vet essential mitigation measures."

Staff Response

CEQA allows an agency to defer the specific details of a mitigation measure when it is impractical or infeasible to include these details during the project's environmental review provided that the agency (i) commits itself to the mitigation, (ii) adopts specific performance standards that the mitigation will achieve, and (iii) identifies the type(s) of potential action(s) that can feasibly achieve those performance standards [CEQA Guidelines Section 15126.4(a)(1)(B)]. Mitigation Measure AQ-4 meets these criteria: the measure requires the County to confirm that the Applicant has prepared and implemented an Odor Prevention and Management Plan prior to operations; adopts specific, objective, and measurable performance standards, in this case regarding the number of odor complaints; and directs the Applicant to identify equipment and procedures to use to address odor issues, including operating procedures to inspect and evaluate the effectiveness of odor control equipment and specifies remedial actions in the event that the performance criteria are not met.

Proper deferment requires the agency to ensure that the mitigation will be in place prior to implementation of the project component that triggers the need for mitigation. In this case, the potential for objectionable offsite odors arises from project operations and not construction. Because the Odor Prevention and Management Plan would be implemented prior to project operations, its timing is not improperly deferred.

In the Final EIR, County staff revised the language of the Odor Management Plan mitigation measure to respond to the same Appellants comments on the Draft EIR. As stated in Mitigation Measure AQ-4 in the Final EIR:

“ Phillips 66 shall develop and implement an Odor Prevention & Management Plan (OPMP). The OPMP shall be an integrated part of daily operations at the Rodeo Site, to effect diligent identification and remediation of any potential odors generated by the Facility.

— The OPMP shall be developed and reviewed by the County in consultation with the BAAQMD prior to operation of the Project, and implemented upon commencement of the renewable fuels processes.

— The OPMP shall be an “evergreen” document that provides continuous evaluation of the overall system performance, identifying any trends to provide an opportunity for improvements to the plan, and updating the odor management and control strategies as necessary.

— The OPMP shall include guidance for the proactive identification and documentation of odors through routine employee observations, routine operational inspections, and odor compliant investigations.

— All odor complaints received by the facility shall be investigated as soon as is practical within the confines of proper safety protocols and site logistics. The goal of the investigation will be to determine if an odor originates from the facility and, if so, to determine the specific source and cause of the odor, and then to remediate the odor.

— The OPMP shall be retained at the facility for Contra Costa County, the BAAQMD, or other government agency inspection upon request.”

Regarding the Rodeo Renewed Project, there would be a significant odor impact. The detailed Odor Prevention & Management Plan will be implemented prior to operation of the Project, when potential odor impacts would be experienced. In addition, the mitigation measure lists the components and steps necessary to mitigate odor impacts, and performance standards are identified. If developed too early, the plan would not be effective. Therefore, the plan will be developed and implemented at the appropriate phase of the project’s construction and during project operation. The document will evolve to maximize effectiveness, which CEQA allows. Therefore, the mitigation measure is acceptable under CEQA and mitigation was not inappropriately deferred.

Regarding the statement that impacts may be considerable depending on what feedstocks are used is irrelevant. The mitigation measure addresses "all odor complaints" that originate from the facility. Regardless of whether the source is from a specific renewable fuel does not matter – the mitigation measure addresses any reported odors.

Appeal Subpoint (f) "Failure to account for cumulative impacts."

The Appellants contend that the Draft EIR does not adequately evaluate cumulative impacts, specifically citing the Marathon Project as not being included in the cumulative analysis. Additionally, due to the cumulative impact of both projects, Appellants state there is a great risk of causing deforestation thus negating any potential climate benefit.

Staff Response

CEQA directs the lead agency to define the geographic scope of the area affected by the cumulative effect and provide a reasonable explanation for the geographic limitation used, which is what the EIR did. Final EIR Master Response No. 3, Cumulative Impacts, provides clarification regarding the cumulative context for assessing the Project's impacts. The EIR used a combination of list of projects as well as future projections based on local regional plans and documents. The cumulative context encompasses the projects that would have the potential to contribute to the significant impacts of the Project, including the Marathon Project. As provided in the Draft EIR, Chapter 6, and further clarified in Master Response 3, County staff did analyze the cumulative effects of both projects, and found that there would be significant and unavoidable adverse impacts that would be cumulatively considerable related to increased vessel traffic and the increased potential for accidental vessel spills. For the other environmental issues identified in the EIR, there would be no significant cumulative impacts because Project-specific mitigation would be implemented to reduce the Project's contribution to the cumulative effect, or the impact was less than significant.

Other Appellant comments indicate County staff should have gone beyond the requirements of CEQA and analyze cumulative impacts from the global perspective. CEQA Guidelines state that an EIR's discussion of cumulative impacts should be guided by the standards of practicality and reasonableness. To require the County to address the global implications of this project is beyond the scope of CEQA – which is a state statute not intended to address nationwide or worldwide implications of an individual project. Master Response 3 of the Final EIR provides a detailed response regarding the scope of the cumulative analysis stating:

"Statements made in the LCFS EA repeatedly emphasize that its program-level evaluation is based on certain predictions about responses to the LCFS program—responses that may or may not be borne out through any given set of projects under examination. The LCFS EA states directly that its predictions are merely "illustrative,", and are rife with uncertainty (refer to LCFS EA, pages 33 and 34), noting the unpredictability of feedstock sourcing locations and market movements. Such language demonstrates CARB's uncertainty about the occurrence, location, and significance of any feedstock-related impacts even in that aggregated setting. The likelihood of any individual project contributing to potential impacts is only less certain. This supports the County's determination that it is overly speculative to draw conclusions about the Project's feedstock-related incremental contribution to any supposed cumulative impact."

Furthermore, Master Response 4 describes the issue of land use change. The response provides the following analysis regarding specificity of feedstock sources and cumulative market impacts:

"This section discusses the agricultural factors, commodity uses and substitutions, incentives and government regulations, and transportation costs affecting the Project's anticipated feedstock use. As further explained, the Project's exact mix of feedstocks and their sources cannot presently be determined because it depends on a web of interconnected variables including weather, commodity prices, individual market participants, and national and international incentives and regulations. The impacts of such variables on availability and sources of feedstocks cannot and need not be modeled as part of this project-level CEQA analysis as described in more detail below."

In addition, Final EIR Master Response 4 addresses potential upstream and downstream effects renewable feedstocks production on a worldwide basis.

Appeal Subpoint (g) "Inconsistency with California climate pathways."

The Appellants contend the Project would provide an oversupply of renewable diesel that exceeds the supply anticipated in analysis of California's climate pathways, and that the Project could actually cause a net increase in greenhouse gas emissions (GHG) by increasing exports.

<u>Staff Response</u>

A key Project objective is to "[p]rovide/maximize production of renewable fuels to assist California in meeting its goals for renewable energy, GHG emission reductions, and reduced CI [carbon intensity] for transportation fuels,". The Project has been designed to achieve this objective and assist California in ultimately transitioning to carbon neutrality (see Draft EIR at page 3-22). The Project's renewable fuels are intended as part of the state's GHG emissions reduction strategies. Consistent with the Governor's Executive Order (EO) B-55-18, which sets a goal to achieve carbon neutrality no later than 2045, CARB is currently in the process of developing the 2022 update to the Scoping Plan with a focus on achieving carbon neutrality by 2045. The EO notes that that "clean renewable fuels play a role as California transitions to a decarbonized transportation sector,".

Among the reports that CARB has stated are informing the 2022 update is the Appellant's referenced study developed for CARB entitled "Achieving Carbon Neutrality in California - PATHWAYS Scenarios Developed for the California Air Resources Board". This document evaluates potential scenarios for achieving carbon neutrality by 2045. In developing this report, the authors reviewed numerous carbon neutrality studies published to date (primarily in Europe) and observed several commonalities among them, including a reliance on "low carbon fuels, including low-carbon electricity and some reliance on low-carbon liquid and gaseous fuels, such as hydrogen, for hard-to electrify sectors," (page 11). The report goes on to note that "Most decarbonization pathways show a significant reliance on low-carbon (or zero carbon) liquid and/or gaseous fuels across all sectors of the economy (buildings, industry, transportation, and electricity) in order to meet climate goals, and in particular when targeting net zero emissions," and includes renewable diesel and renewable jet fuel in its use of the term biofuel (page 27). Of the three pathways to 2045 carbon neutrality considered in this report, renewable transportation fuel is a consistent component in each of them.

Discussion regarding other relevant reports and regulations can be found in Final EIR Master Response No. 6, Purpose of Project. Consistent with these various federal, state, and regional goals, the Project helps to mitigate climate change by contributing to the reduction of GHG emissions within industries that are difficult to decarbonize, such as heavy industry and aviation, where use of renewable fuels will ultimately help lower the lifecycle carbon emissions of their transportation fuel. The Project provides a mechanism for compliance with California's LCFS and Cap-and-Trade programs and the RFS, while continuing to meet regional market demand for transportation fuels. As discussed above, development and deployment of renewable transportation fuels is a component of a suite of measures intended to help achieve California's goal of carbon neutrality by 2045.

Appeal Subpoint (h) "Failure to adequately mitigate transportation risk impacts."

The Appellant contends that concerns provided in comments on the Draft EIR with regard to marine impacts were dismissed by County staff under the assumption that non-petroleum feedstocks will react to cleanup methodologies identical to petroleum. It is further stated 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.

<u>Staff Response</u>

As stated in the Draft EIR Section 4.9, Hazards and Hazardous Materials, generally renewable feedstocks are not identified as marine pollutants by the US Department of Transportation (USDOT, Title 49 Part 171), the United Nations, or the International Maritime Organization, which regulate the movement of materials throughout the world. However, although renewable feedstocks may not be classified as pollutants, the USEPA "found that a worst-case discharge or substantial threat of discharge of animal fats and vegetable oils to navigable waters, adjoining shorelines, or the exclusive economic zone could reasonably be expected to cause substantial harm to the environment, including wildlife that may be killed by the discharge" (40 CFR Part 112).

The EIR acknowledges (Final EIR page 4-5) the feedstocks handled at the Marine Terminal are not regulated under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (e.g., renewable feedstocks such as soybean oil and tallow) and therefore not subject to Office of Spill Prevention and Response (OSPR) oversight, and are also not subject to the California State Lands Commission (CSLC) oversight efforts (Marine oil Terminal Engineering and Maintenance Standards [MOTEMS], Article 5, Article 5.3 and Article 5.5, depending on the materials handled). Regulated products (i.e. "Oil" and "Renewable Fuels" defined in Pub. Resources Code sec. 8750), however, will continue to be transferred at the Marine Terminal, which do require MOTEMS-compliant Terminal Operating Limits for those products that reside within the jurisdiction of the CSLC. In addition, Assembly Bill 148, adopted in 2021, defined the terms "renewable fuel," "renewable fuel production facility," and "renewable fuel receiving facility" for purposes of the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, which includes renewable fuel within the definition of "oil" for purposes of the act.

To minimize impacts, the County is requiring that the Applicant comply with the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act for all vessels calling at the Marine Terminal regardless of feedstock material type (refer to Mitigation Measure HAZ-1 below). In addition, Mitigation Measure HAZ-2 requires a coordinated response with the Facility and Oil Spill Response Organization for on-water equipment deployment and recovery to protect sensitive shoreline and nearshore resources. Mitigation Measure BIO-3 requires that the Applicant's Facility Response Plan and Spill Prevention, Control, and

Countermeasure Plan be updated to address the change in proposed feedstocks, and also requires consultation with OSPR to address how to quickly contain a spill of renewable feedstocks.

In summary, EIR mitigation measures require that the renewable feedstocks be addressed under the same regulations as petroleum-based products, and the recent addition of renewable fuels under Assembly Bill 148, to minimize impacts. However, because the risk of a spill cannot be eliminated, it was determined potential impacts on water quality and special-status species and their habitat would remain significant and unavoidable despite implementation of these mitigation measures.

As with any regulation, experience will dictate new and revised regulations to address the use, transport, treatment and disposal of renewable feedstocks. Until that time, and for the purposes of the proposed project, and in line with USEPA 40CFR112, it was assumed the project's use of renewable feedstocks and production of renewable fuels would be as detrimental as petroleum-based feedstocks and fuels, which could cause substantial harm to the environment in the event of an accidental spill. Therefore, a spill was identified as a significant and unavoidable impact, to be addressed by the following mitigation measures:

Mitigation Measure HAZ-1 - Implement Release, Monitoring and Avoidance Systems

[Begin Citation] - "The following actions shall be completed by Phillips 66 prior to Project operations, including the transitional phase, and shall include routine inspection, testing and maintenance of all equipment and systems conducted in accordance with manufacturers' recommendations and industry guidance for effective maintenance of critical equipment at the Marine Terminal.

Feedstocks handled at the Marine Terminal are not regulated under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) (e.g. renewable feedstocks such as soybean oil and tallow) and therefore not subject to OSPR oversight, and are also not subject to the CSLC oversight efforts (MOTEMS, Article 5, Article 5.3 and Article 5.5, depending on the materials handled). Yet materials may be detrimental to the environment if spilled.

Regulated products (i.e. "Oil" and "Renewable Fuels" defined in Pub. Resources Code sec. 8750) will continue to be transferred at the Marine Terminal, which do require MOTEMS-compliant Terminal Operating Limits for those products that reside within the jurisdiction of the CSLC. To ensure that Project operation continues to meet those standards, the following measures are required.

Applicability of MOTEMS, Article 5, 5.3, 5.5 and Spill Prevention Requirements.

As some materials transferred at the terminal may be feedstocks or other non-regulated materials/feedstocks/products, Phillips 66 shall comply with the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) for all vessels calling at the Marine Terminal regardless of feedstock/material type. In addition, MOTEMs operational regulations, as codified in Article 5. Marine Terminals Inspection and Monitoring (2CCR §2300 et seq), Article 5.3 Marine Terminals Personnel Training and Certification (2CCR §2540 et seq), and Article 5.5 Marine Terminals Oil Pipelines (2CCR §2560 et seq), including items such as static liquid pressure testing of pipelines, shall be implemented for all operations at the Marine Terminal regardless of feedstock/material type and LKS Act regulatory status.

Upon request, Phillips 66 shall provide evidence to relevant regulatory agencies that these facilities, operational response plans, and other applicable measures have been inspected and approved by CSLC and OSPR and determined to be in compliance.

If terminal operations do not allow for regular compliance and inspection of LKS and MOTEMS requirements by the CSLC and OSPR, Philips 66 shall employ a CSLC-approved third-party to provide oversight as needed to ensure the same level of compliance as a petroleum-handling facility, and to ensure maximum protection of the environment from potential spills and resulting impacts. Phillips 66 shall provide evidence of compliance upon request of relevant regulatory agencies.

Remote Release Systems.

The Marine Terminal has a remote release system that can be activated from a single control panel or at each quick-release mooring hook set. The central control system can be switched on in case of an emergency necessitating a single release of all mooring lines. However, to further minimize the potential for accident releases the following is required:

— Provide and maintain mooring line quick release devices that shall have the ability to be activated within 60 seconds.

—These devices shall be capable of being engaged by electric/push button release mechanism and by integrated remotely-operated release system.

—Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).

— Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.

— In consultation with the CSLC and prior to Project operation, Phillips 66 shall provide a written evaluation of their existing equipment and provide recommendations for upgrading equipment to meet up-to-date best achievable technology standards and best industry practices, including but not limited to consideration of equipment updates and operational effectiveness (e.g. visual and audible alarm options, data display location and functionality, optional system features). Phillips 66 shall follow guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4.

Best achievable technology shall address:

— Functionality – Controlled release of the mooring lines (i.e. a single control system where each line can be remotely released individually in a controlled order and succession) vs. release all (i.e. a single control system where all lines are released simultaneously via a single push button). See SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.2.1.

—Layout – The location(s) of the single control panel and/or central control system to validate that it is operationally manned such that the remote release systems can actually be activated within 60 seconds.”

This measure would allow a vessel to leave the Marine Terminal as quickly as possible in the event of an emergency (fire, explosion, accident, or tsunami that could lead to a spill). In the event of a fire, tsunami, explosion, or other emergency, quick release of the mooring lines within 60 seconds would allow the vessel to quickly leave the Marine Terminal, which could help prevent damage to the Marine Terminal and vessel and avoid and/or minimize spills. This may also help isolate an emergency situation, such as a fire or explosion, from spreading between the Marine Terminal and vessel, thereby reducing spill potential. The above would only be performed in a situation where transfer connections were already removed and immediate release would not further endanger terminal, vessel and personnel.

Tension Monitoring Systems.

— Provide and maintain Tension Monitoring Systems to effectively monitor all mooring line and environmental loads, and avoid excessive tension or slack line conditions that could result in damage to the Marine Terminal structure and/or equipment and/or vessel mooring line failures.

— Line tensions and environmental data shall be integrated into systems that record and relay all critical data in real time to the control room, Marine Terminal operator(s) and vessel operator(s).

— All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM (e.g. vessels are berthing within the MOTEMS compliant speed and angle Rodeo Renewed Project Final Environmental Impact Report March 2022 Comment Letter 2. California State Lands Commission (CSLC) 3-111 requirements), and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing).

— System shall include, but not be limited to, quick release hooks only (with load cells), site-specific current meter(s), site-specific anemometer(s), and visual and audible alarms that can support effective preset limits and shall be able to record and store monitoring data.

— Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).

— Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers’ recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 “Jetty Maintenance and Inspection Guide” Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.

— Install alternate technology that provides an equivalent level of protection.

— All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis.

The Marine Terminal is located in a high-velocity current area and currently has only limited devices to monitor mooring line strain and integrated environmental conditions. Updated MOTEMS Terminal

Operating Limits (TOLs), including breasting and mooring, provide mooring requirements and operability limits that account for the conditions at the terminal. The upgrade to devices with monitoring capabilities can warn operators of the development of dangerous mooring situations, allowing time to take corrective action and minimize the potential for the parting of mooring lines, which can quickly escalate to the breaking of hose connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a petroleum product spill. Backed up by an alarm system, real-time data monitoring and control room information would provide the Terminal Person-In-Charge with immediate knowledge of whether safe operating limits of the moorings are being exceeded. Mooring adjustments can be then made to reduce the risk of damage and accidental conditions.

Allision Avoidance Systems.

— Provide and maintain Allision Avoidance Systems (AASs) at the Marine Terminal to prevent damage to the pier/wharf and/or vessel during docking and berthing operations. Integrate AASs with Tension Monitoring Systems such that all data collected are available in the Control Room and to Marine Terminal operator(s) at all times and vessel operator(s) during berthing operations. The AASs shall also be able to record and store monitoring data.

— All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing).

— Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).

— Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide", are Rodeo Renewed Project Final Environmental Impact Report 3-112 Comment Letter 2. California State Lands Commission (CSLC) March 2022 required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.

— Velocity monitoring equipment is required to monitor reduced berthing velocities until permanent MOTEMS-compliant corrective actions are implemented.

— The systems shall also be utilized to monitor for vessel motion (i.e. surge and sway) during breasting/mooring operations to ensure excessive surge and sway are not incurred.

The Marine Terminal has a continuously manned marine interface operation monitoring all aspects of the marine interface. The Automatic Identification System is monitored through TerminalSmart and provides a record of vessel movements. Pursuant to the CSLC January 26, 2022 letter entitled Phillips 66 (P66) Rodeo Marine Terminal – Review of New September 2021 Mooring & Berthing Analyses and Terminal Operating Limits (TOLS), the single cone fenders shall not be used as the first point of contact during berthing operations. Therefore, all berthing operations shall utilize the double cone fenders. P66 shall incorporate TOL diagrams with landing point statements in the Terminal Information Booklet. For all vessels, a Phillips 66 Marine Advisor is in attendance and is in radio contact with the vessel master and pilot prior to berthing, reviewing initial contact point and then monitoring.

Excessive surge or sway of vessels (motion parallel or perpendicular to the wharf, respectively), and/or passing vessel forces may result in sudden shifts/redistribution of mooring forces through the mooring lines. This can quickly escalate to the failure of mooring lines, breaking of loading arm connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a spill. Monitoring these factors will ensure that all vessels can safely berth at the Marine Terminal and comply with the standards required in the MOTEMS."

Mitigation Measure HAZ-2: USCG Ports and Waterways Safety Assessment (PAWSA) Workshops, Spill Response and Pilotage Requirements

"— Phillips 66 shall participate in the USCG's PAWSA workshops for the San Francisco Bay Area (Bay Area) to support overall safety improvements to the existing Vessel Traffic Service in the Bay Area or approaches to the bay if such workshops are conducted by the USCG during the life of the lease.

— Spill Response to Vessel Spills. Phillips 66 shall respond to any spill near the Marine Terminal from a vessel traveling to or from the Marine Terminal or moored at the Marine Terminal as if it were its own, without assuming liability, until such time as the vessel's response organization can take over management of the response actions in a coordinated manner.

— For all tankers and barges, Phillips 66 shall require that pilotage is utilized while transiting the Bay Vessels 300 GRT or larger and will cooperate in meeting USCG/NOAA VSR program to keep speed limited to 10 knots in the Bay and lower upon approach to the Marine Terminal due to tug escort speed limitations.

Vessel owners/operators are responsible for spills from their tankers. Tanker and barge owners/operators are required by federal and state regulations to demonstrate that they have, or have under contract, sufficient response assets to respond to worst-case releases. Tankers and barges operating in United States and California waters must certify that they have the required capability under contract. All terminals are under contract with one or more OSRO to respond to spills with all the necessary equipment and manpower to meet the response requirements dictated by regulations. This mitigation would further reduce the risk of spills in the San Francisco Bay or near approaches to the bay by requiring participation in USCG Ports and Waterways Safety Assessment workshops for the Bay Area to improve transit issues and response capabilities in general, and to support overall safety improvements to the existing VTS in the future.

While vessel owners/operators are responsible for their spills, if a spill were to occur near the Marine Terminal, Phillips 66 and its contractors may be in a better position to provide immediate response to a spill using their own equipment and resources, rather than waiting for mobilization and arrival of the vessel's response organization. The Phillips 66 staff is fully trained to take immediate action in response to spills. Such action could result in a quicker response and more effective control and recovery of spilled product. This mitigation would also require Phillips 66 to respond to any spill from a vessel traveling in the San Francisco Bay to or from the Marine Terminal or moored at its wharf, without assuming liability, until the vessel's response organization can take over management of the response actions in a coordinated manner. This requirement would further limit the potential for impacts from spills in the San Francisco Bay from vessels calling at the Marine Terminal.

In addition, Phillips indicates that it is their policy to utilize pilots for all tankers and barges while within the bay, even if the tanker or barge is under the required size requirements, and to limit vessels speeds below the required maximum. This mitigation ensures that all tankers and barges utilize pilots and speed limits in order to reduce the probability of groundings, collisions or allisions."

Mitigation Measure BIO-3: Update and Review Facility Response Plan and Spill Prevention, Control, and Countermeasure Plan with OSPR

"—The Facility Response Plan and Spill Prevention, Control, and Countermeasure (SPCC) Plan shall be updated to address the change in proposed feedstocks. Phillips 66 will consult with OSPR during update of the SPCC Plan, especially adequacy of booms at the Marine Terminal to quickly contain a spill of renewable feedstocks.

— In accordance with CCR Title 14, Chapter 3, Subchapter 3, several types of drills are required at specified intervals. Due to the potential for rapid dispersion of biofuels and oils under high energy conditions, Phillips 66 shall increase the frequency of the following drills to increase preparedness for quick response and site-specific deployment of equipment under different environmental conditions.

— Semi-annual equipment deployment drills to test the deployment of facility-owned equipment, which shall include immediate containment strategies, are required on a semiannual pass/fail basis – if there is fail during first six months, then another drill is required. Phillips 66 will require that both semi-annual drills are conducted and schedule them under different tide conditions.

- An OSRO field equipment deployment drill for on-water recovery is required at least once every three years. Phillips will increase the frequency of this drill to annual.

- CDFW-OSPR shall be provided an opportunity to help design, attend and evaluate all equipment deployment drills and tabletop exercises. To ensure this, Phillips 66 shall schedule annual drills during the first quarter of each year to ensure a spot on OSPR's calendar." - [End Citation]

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

Appellants contend the Final EIR Improperly rejected the direction of BAAQMD, and the request of commenters, to include modified unit 250 in the project analysis.

Staff Response

Unit 250 is not part of or operationally related to the Project and can process feedstocks with or without the Project. Unit 250 did undergo modification in 2021 to obtain the flexibility to process both petroleum and renewable feedstocks; however, the air emissions did not change with these modifications. Since Unit 250 has been in operation since 2021, it is included in the EIR analysis as part of the baseline.

As explained in the Master Response No. 7 in the Final EIR – "Project Description – Piecemealing", Unit 250 is an existing piece of equipment at the Rodeo facility that, because of its inherent capability and unique flexibility, was updated last year to process both petroleum-based and renewable feedstocks, and it started processing renewable feedstocks in April 2021.

Unit 250 has been operating at the Rodeo facility since 2005 and was permitted as the primary unit for producing Ultra Low Sulfur Diesel. Beginning in at least 2017, Phillips 66 began exploring the option of co-processing renewable feedstocks in Unit 250.

In their comments to the Draft EIR, Appellants claimed that Unit 250 is part of the Rodeo Renewed Project based on assumptions regarding Unit 250's role at the Rodeo facility, and the County responded to these comments in Master Response No. 7, explaining that Unit 250 was an independent project. Unit 250 has processed renewable feedstocks for nearly a year and does not rely on the Rodeo Renewed Project, and the Rodeo Renewed Project could be constructed and implemented without Unit 250. Conversely, if Rodeo Renewed is not implemented, Unit 250 can and will continue to process both renewable and petroleum-based feedstocks, either selection of which is dependent on market conditions, feedstock availability, and logistics economics and capabilities.

Large industrial facilities frequently update and upgrade equipment, and many such improvements are independent of long-term projects being processed by that facility. These long-term projects often take years to process, and ongoing changes to existing equipment often proceed independently, as not all changes to an industrial facility are linked to long-term projects. Here, Unit 250 operations are functionally independent of the Rodeo Renewed Project.

The EIR's project description is clear and consistent about Unit 250. The Executive Summary, Project Description, and Alternative Analyses sections of the Draft EIR explicitly reference Unit 250 as being part of the existing facility and not part of the Rodeo Renewed Project: "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." (Draft EIR, Table ES-1, Asterisk to Table, p. xxii of Executive Summary; Draft EIR, Table 3-2, footnote a, p. 3-24 of Project Description.)

The Draft EIR explained with respect to the No Project Alternative:

"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."

(see also Draft EIR, Table 5-1, footnote d, p. 5-11 of Alternatives Analysis)

The County explained the operations of Unit 250 throughout the CEQA process, and the Rodeo Renewed Project has been described accurately and consistently throughout the EIR.

Although Unit 250 is not required by CEQA to be included as part of the Rodeo Renewed Project, the air emissions from Unit 250 are included in the FEIR's air emissions calculations based on 2019 operations when Unit 250 processed petroleum-based feedstocks. [FEIR, Appendix B, Attachment B, Stationary Source Table 1.] Existing equipment that was not part of the Project, including Unit 250, were included in both the baseline and the post-Project calculations of air emissions. Again, these amounts for Unit 250 were based on processing petroleum-based feedstocks. This is important because Appellants are demanding that Unit 250 emissions be included in the Project, and while Unit 250 (updated to process renewable fuels) is not part of the Project, the air emissions from Unit 250 (processing petroleum-based feedstocks) are included in the post-Project calculations. Thus, the purported environmental effect that Appellants seek to have considered in the FEIR relates solely to the delta or difference between Unit 250's processing of petroleum-based feedstocks and renewable feedstocks.

However, the difference in air emissions between Unit 250's processing of petroleum-based feedstocks and renewable feedstocks is negligible, as renewable fuels processing operates within the same range of operations as petroleum-based operations. Using a five-year average (2017-2021) of Unit 250's emissions, the 2021 air emissions from Unit 250 processing renewable feedstocks for all criteria pollutants are approximately the same, with NOx and SO2 increasing by 0.06 and 0.09 tons per year, respectively, and CO, POC and PM 10/2.5 decreasing by 0.01, 0.05 and 0.08 tons per year.

Furthermore, the 2021 air emissions from Unit 250 are negligible as compared to air emissions for the Project as a whole, and adding (or subtracting) these differences from the post-Project totals do not change the resulting CEQA impacts to air quality. (Draft EIR, Table 4.3-15.) The post-Project air emissions from Unit 250 (processing renewable feedstocks) constitute approximately 0.52% or less for any criteria air pollutant of the total post-Project air emissions for facility stationary sources.

Using the delta, the Unit 250 air emissions as compared to the post-Project air emission totals for facility stationary sources decrease with respect to CO, POC and PM 10/2.5, and increase by 0.03% for NOx and SO2.

In addition, the greenhouse gas (GHG) emissions for Unit 250 processing renewable fuels decrease substantially as compared to Unit 250 processing petroleum-based fuels, a reduction of 1,912 metric tons per year. This decrease is a small percentage compared to the total GHG emissions for facility stationary sources at 0.18% (Draft EIR, Table 4.8-5), but contributes to the Project's overall decrease in GHG emissions.

Appellants seek to have Unit 250 emissions added to the Project, which would be improper under CEQA, but in no case does it affect the resulting impacts to air quality or GHG emissions – all remain less than significant. No discretionary permits were required from the County to process renewable fuels feedstocks from Unit 250.

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

Appellants contend the Final EIR fails to comply with the CEQA, stating the Final EIR did not respond to comments pertaining to project greenhouse gas emissions and potential hydrogen "debottlenecking" impacts of certain project components.

<u>Staff Response</u>

This is not the case. As stated in Staff Response to appeal topic (a) above, and reiterated here, the Draft EIR provides a complete discussion and analysis of the hydrogen uses associated with the project. At maximum operating limits the Project would require an additional 36.74 million scf/day or approximately 35 percent more hydrogen above baseline conditions, and the Draft EIR includes this 35 percent increase in hydrogen use in the air emissions modeling. Even though the hydrogen use per barrel of feed may increase, the processing units will process fewer barrels of renewable feedstocks as compared to crude oil feedstocks, and the overall hydrogen usage per processing unit is within this historic range of the Rodeo Refinery. Accordingly, hydrogen demand of a renewable diesel hydrotreater (or hydroprocesser) is similar to that of existing process units at Rodeo Refinery. Impacts related to the increased use of hydrogen are found to be less than significant. Therefore, the Draft EIR does not dismiss the increase in hydrogen use and the Project would not produce more renewable fuels than reported in the Draft EIR.

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

The Appeal notes that the FEIR reviews three alternatives in addition to the no project alternative, and identifies an "environmentally superior" alternative. But the Appeal contends that the FEIR does not identify the "preferred alternative" and that identification of the "preferred alternative" should be supported by findings based on evidence in the record.

Staff Response

DEIR Section 5, Alternatives Analysis, pursuant to CEQA Guidelines 15126.6, Consideration and Discussion of Alternatives to the Proposed Project, analyzed the No Project Alternative, the Reduced Project Alternative, the Terminal Only Alternative, and the No Temporary Increase in Crude Oil Alternative. The chapter reviews impacts of each alternative for each environmental topic, noting the level of significance of the impact compared to the impacts of the Project.

Section 5.5.4.3, Table 5-2, Summary Comparison of the Environmental Effects of Alternatives Relative to the Project summarizes and compares the alternatives with the Project. The Project would have unavoidable significant environmental impacts, even considering implementation of feasible mitigation measures, related to air quality, biology, hazards and hazardous materials, and hydrology and water quality. Table 5-2 shows that the Reduced Project Alternative would also have significant unavoidable impacts for the four topics above, although the degree of effect would be reduced for biology, hazards and hazardous materials, and hydrology and water quality. In accordance with CEQA Guidelines15126.6(e)(2), Section 5.6 (Environmentally Superior Alternative) concludes the Reduced Project Alternative to be the environmentally superior alternative:

"The Reduced Project Alternative would be the Environmentally Superior Alternative under CEQA. This alternative would meet or partially meet all but one of the Project objectives. The only objective not met is to maintain the facility's current capacity to supply regional market demand for transportation fuels, including renewable and conventional fuels. The Reduced Project Alternative would not maintain the capacity to produce approximately 120,000 bpd to supply regional market demand for both renewable and conventional fuels, as it would provide an overall supply of 102,000 bpd (50,000 bpd of renewable fuels, 40,000 bpd of conventional fuels, and 12,000 bpd of existing capacity for renewable fuels). However, this alternative would reduce the number of annual marine vessels to 326 instead of 362, as proposed under the Project. Other elements of the Reduced Project would be identical to the Project, including demolition of the Carbon Plant and the Santa Maria Site, and cleaning and removal from active service of the Pipeline Sites."

CEQA does not require identification of, or findings for, a "preferred alternative." The FEIR reviews alternatives to the Project and identifies for the record the conclusions for the Environmentally Superior Alternative.

Nevertheless, staff has prepared additional findings to supplement the findings made by the County Planning Commission under Public Resources Code section 21081(a) and CEQA Guidelines section 15091(a), including specific findings related to the alternatives analyzed in the environmental impact report. The additional findings are included in the CEQA findings in the project's Findings and Conditions of Approval (see Attachment 2).

Project Throughput Limits. The Appeal contends that the FEIR does not discuss conditions of Project approval that would limit Refinery throughput to 67,000 barrels per day (bpd) of feedstock. The Appeal states that EIR analyzed the impact of 67,000 bpd, "yet nothing in the conditions limits the Refinery to that amount."

As analyzed in the FEIR, the Project would propose to process up to 67,000 barrels per day (bpd) of renewable feedstock. DEIR Chapter 3, Project Description, under Section 3.5 Project Overview, page 3-22 states:

"The Project would produce up to 55,000 bpd of a variety of renewable transportation fuels from renewable feedstocks. The Rodeo Refinery as a whole post-Project would produce up to 67,000 bpd."

Section 3.7 Project Operation, page 3-23 then states:

"Of the 67,000 bpd of renewable fuels that would be produced, 55,000 bpd would occur as a result of the Project. This amount would be in addition to the Rodeo Refinery's existing capability (as of 2021) of producing 12,000 bpd from pretreated feedstocks using Unit 250 (previously used to process petroleum-based feedstocks)."

The 67,000-bpd throughput limit is both a physical limit based on the configuration of the facility and a legal limit based on permitting constraints that will be implemented by BAAQMD. The 67,000-bpd throughput would be limited, as noted above, by on-site operating conditions. Further, the EIR discusses that Project throughput would be subject to Bay Area Air Quality Management District (BAAQMD) regulations and permitting.

DEIR Section 4.3, Air Quality, explains that the Project would require an Authority to Construct (ATC) from the BAAQMD. That ATC permit would be based on the proposed 67,000 bpd throughput. Section 4.3.3.5, page 4.3-44, notes that the Phillips 66 has submitted an application to the BAAQMD for an Authority to Construct permit to updated its operating permit for the Project.

Therefore, Project throughput, with an approved BAAQMD ATC, would be limited to 67,000 bpd. Any proposed increase in that throughput would require BAAQMD review and approval, including, as appropriate, CEQA review. If Phillips 66 were to desire to increase throughput limits, that change to the project would require a modified BAAQMD permit. If there is a substantial change to the project because of a proposed increase in the throughput limit, the substantial change would trigger subsequent environmental review under CEQA (CEQA Guidelines, § 15162).

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

The Appellants contend the Final EIR presents new information that should have been disclosed for public comment during the Draft EIR comment period.

Staff Response

Pursuant to CEQA Guidelines Section 15088.5(a), recirculation of a Draft EIR is required only if:

"1) a new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented;

2) a substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance;

3) a feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it; or

4) the draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded."

All aspects of the project were fully disclosed and discussed in the Draft EIR. All information and materials provided in the Final EIR in response to comments constitutes only clarifying information that supports the analysis contained in the Draft EIR. No new analysis or information was provided that requires public review. None of the text edits or changes to the Draft EIR meet any of the above conditions.

Therefore, recirculation of any part of the Draft EIR is not required. The information presented in the Draft and Final EIRs support this determination by the County.

Appeal Point VI. "The Statement of Overriding Considerations is Inadequate"

Appellants contend that the County's statement of overriding considerations is inadequate in that it is used in place of feasible mitigation measures. Appellant contend, specifically, that the County failed to analyze the alternative of reduced throughput and that the mitigation for proposed for odors is inadequate and unlawful.

Staff Response

Staff's response to Appellants' contention regarding the County's alternatives analysis is discussed above in the staff response to appeal topic IV. Staff's response to Appellants' contention regarding the Odor Management Plan is discussed above in the staff response to appeal topic I(e).

As the lead agency under CEQA for preparation, review, and certification of the FEIR, the County is responsible for determining the potential environmental impacts of the proposed project, which of these impacts would be significant, and which impacts can be mitigated through implementation of feasible mitigation measures to avoid or minimize such impacts to a level of "less than significant".

CEQA requires the lead agency to balance the benefits of a proposed project against its significant and unavoidable adverse impacts when determining whether to approve the project. In particular, Public Resources Code Section 21081(a) provides that no public agency may approve or carry out a project for which an environmental impact report has been certified that identifies one or more significant effects on the environment that would occur if the project is approved or carried out, unless the public agency makes one or more of three findings with respect to each significant effect.

A public agency may find that specific economic, legal, social, technological, or other considerations, including considerations for the provision of employment opportunities for highly trained workers, make infeasible the mitigation measures or alternatives identified in the EIR and thereby leave significant unavoidable effects. Under Public Resources Code Section 21081(b), before approving the project, the lead agency must also find that the economic, legal, social, technological, or other benefits of the project outweigh the significant effects of the project.

When the lead agency approves a project which would result in significant effects identified in the FEIR, but would not be avoided or substantially lessened, the agency must state in writing the specific reasons to support its action based on the Final EIR and/or other information in the record. The County's CEQA Findings and Statement of Overriding Considerations (Statement) in the CEQA findings in the project's Findings and Conditions of Approval (see Attachment 2), meet that requirement.

The County's Statement discusses the rationale for approving the Project based on the infeasibility of implementing mitigation measures to sufficiently reduce identified impacts and the project's outweighing benefits. As noted in the Statement, the Project benefits, individually and collectively, outweigh potential significant unavoidable adverse impacts.

Key findings in the Statement are summarized below.

The County finds that the project will provide the following benefits to the residents of the County and of the State of California:

1. Reductions in Greenhouse Gas Emissions from the Combustion of Renewable Fuels: The combustion of renewable fuels produced by the project would result in reductions of greenhouse gas emissions of approximately 45-75 percent as compared to petroleum-based fuels. Based on the carbon intensity of the renewable diesel sold in California in 2021, the project would reduce the lifecycle carbon emissions of transportation fuels by approximately 8.5 million metric tons per year. (Final EIR, p. 3-50.)

2. Attainment of Regulatory and Policy Goals: The Rodeo Renewed Project transforms an existing crude oil production facility into a renewable fuels processing facility providing for the production of up to 55,000 barrels of renewable transportation fuels per day to assist California in meeting a number of goals. The project's renewable fuels products would produce fewer lifecycle GHG emissions per barrel, and their use in transportation would have a lower carbon footprint than conventional petroleum-based fuels.

   — Assist Attainment of Goals. Governor Newsom's Executive Order N-79-20 states: "clean renewable fuels play a role as California transitions to a decarbonized transportation sector" and "to support the transition away from fossil fuels consistent with the goals established in this Order and California's goal to achieve carbon neutrality by no later than 2045, the California Environmental Protection Agency and the California Natural Resources Agency, in consultation with other State, local and federal agencies, shall expedite regulatory processes to repurpose and transition upstream and downstream oil production facilities..." The Governor's Order also directs CARB to "develop and propose strategies to continue the State's current efforts to reduce the carbon intensity of fuels beyond 2030 with consideration of the full life cycle of carbon. Additionally, the California Air Resources Board's November 19, 2020, "California's Greenhouse Gas Goals and Deep

Decarbonization" presentation anticipates that biofuels will comprise 19 percent of the transportation "fuel" sector by 2045." As a major producer of renewable fuels, the project would materially contribute to California's efforts to meet the goals of Executive Order N-79-20.

— Compliance With Federal and State Standards. The federal Renewable Fuel Standard (RFS) program was created under the Energy Policy Act of 2005 as an amendment to the Clean Air Act (CAA), and expanded by the Energy Independence and Security Act of 2007. EPA implements the program in consultation with U.S. departments of Agriculture and Energy. The RFS requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel. The program has a goal of producing, nationally, 36 billion gallons of total renewable fuel per year; by producing over 800 million gallons of renewable fuels per year the project would materially promote that goal.

Under California Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006, refineries are subject to regulations aimed at reducing California's global warming emissions and transitioning to a sustainable, low-carbon future (CARB 2021). The latest Update to the Climate Change Scoping Plan (CARB 2017) sets goals of a 40-percent GHG emission reduction below 1990 emission levels by 2030 and a substantial advancement toward the 2050 goal to reduce emissions by 80 percent below 1990 emission levels. Key provisions of AB 32 include the Low-Carbon Fuel Standard, which is intended to reduce California's dependency on petroleum by encouraging the provision of low-carbon and renewable alternative fuels, and the Cap-and-Trade Regulation, which discourages major sources of GHG emissions and encourages investment in cleaner, more efficient technologies. By increasing production of renewable fuels, the project will provide a mechanism for compliance with these provisions through providing facilities in California.

Furthermore, by reducing emissions of air pollutants from existing conditions, the project will forward the goals of the Bay Area Air Quality Management District's 2017 Clean Air Plan. Specifically, the project would be consistent with the plan's Refinery Emissions Reduction Strategy by eliminating sources associated with petroleum refining, and with the plan's call for refineries to transition to clean energy companies by 2050.

3. Maintaining Current Employment Levels: Numerous letters of support for the project were received during the comment period from labor unions and individuals citing the retention of family-wage jobs and the creation of construction jobs as key benefits of the project. The project will preserve and protect approximately 650 existing family-wage jobs in Contra Costa County and will continue to provide indirect support to thousands of other jobs in the Bay Area. In addition, construction of the project will provide up to 500 construction jobs.

4. Sustainability and Reinvestment in Community: The Rodeo Renewed Project is a substantial investment in the community and facility and supports sustainability by re-using and transforming an existing industrial facility and by producing renewable transportation fuels.

5. Transportation Fuel Supply Security: Interruptions in the regional supply of transportation fuels have occurred as a result of refinery shutdowns for various reasons. These incidents have adversely affected Contra Costa County's residents and businesses through inconvenience and higher fuel prices. A reliable supply of fuels is thus essential for the economic well-being of the region. The project will maintain the Rodeo facility's current capacity to supply regional market demand for

transportation fuels by producing up to 67,000 barrels of renewable fuels per day and distributing up to 40,000 barrels of conventional gasoline per day. Furthermore, shortages that could result from a refinery shut-down during construction of the project will not occur because the project will continue to import and refine crude oil during the project construction period.

6. Recycling Benefits: Recycling organic wastes and by-products such as used cooking oils, rendering wastes, and other fats, oils, and greases has a number of environmental and financial benefits. These include reducing demand on landfill space, reducing the carbon footprint of fuels, and generating a second revenue stream from the same material. These benefits improve quality of life and help businesses thrive. By accepting large quantities of recyclable fats, oils, and grease to be processed into renewable fuels, the project will help Contra Costa County, the region, and the State of California realize those benefits.

7. Demolition of Santa Maria Refinery and Carbon Plant: The project provides for the demolition of these two sites, eliminating uncertainty regarding the re-use of these sites as currently developed.

8. Reduction of Truck Traffic near Rodeo: Rodeo Refinery truck traffic in 2019 consisted of approximately 40,000 roundtrips per year. With the Rodeo Renewed Project, including the elimination of truck traffic from the Carbon Plant, truck traffic would be reduced to approximately 16,000 truck roundtrips per year.

9. Reductions in Energy Usage (Electricity and Natural Gas): The proposed Project would result in modest reductions in electricity usage and substantial reductions in natural gas usage.

   Each of these benefits are sufficient to outweigh the adverse environmental impacts of the proposed Project and to justify approval of the project and certification of the EIR.

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

Staff Response

The appeal raises concerns with the provisions of the project conditions of approval related to site cleanup, including concerns regarding the timeline being too slow; lack of provisions to include soil remediation in the work plan or the costs of this work in a modified corporate guarantee; need for annual review of corporate guarantee; and required cleanup levels not aggressive enough.

Staff does not concur with these concerns as the conditions that have been proposed for the project related to site cleanup would establish for the first time provisions and standards the County can enforce regarding demolition and removal of the facility and investigation of soil conditions. These conditions not only address clean-up related to the proposed project but also achieve significant public benefits by establishing parameters for clean-up of the site as whole so it can be productively put to another use in the future. Construction of the Rodeo Refinery occurred well before zoning laws came into effect in California, and neither the County, nor to our knowledge any other agency, has regulations of general applicability to industrial or other facilities that impose requirements, a schedule and financial assurances for demolition, soil investigation and cleanup.

Conditions of approval 5 through 8 address the cleanup of the entire facility and include the following overview of the requirements:

"The Permittee shall demolish and remove all portions of the facility that will not be used for any phase of the Project or any intended future use of the facility. Upon the permanent closure of the facility, the Permittee shall demolish and remove all remaining portions of the facility. During the operation of the Project, the Permittee shall investigate soil conditions at the site and, where necessary, clean-up and restore the site to a condition suitable for commercial and industrial land uses."

To assure the performance of these requirements, a number of detailed provisions are included in the conditions, including requirements for creating and updating a Work Plan to establish the specific schedule for demolition, investigation and cleanup and for a Corporate Guarantee to assure there is funding for the work (initial value of the Guarantee will be $100 million).

The conditions include reasonable provisions regarding the timeline for investigating soil conditions and demolishing portions of the facility that will not be used for the Project. The Contra Costa Carbon Plant located east of Interstate 80 and visible from Highway 4 is required to be demolished and removed no later than two years following the commencement of operations of the Project. In addition, the process units that have operating permits relinquished as part of the Project, such as Crude Unit 267, Sulfur Plant 236 and Sulfur Plant 238, must be demolished and removed within 5 years of permanent cessation of operations in the respective process units. The initial Work Plan, required to be submitted within 30 months of approval of the land use permit for the Project, will establish the schedule for remaining demolition work as well as soil investigation and clean-up work. The Work Plan must include a series of detailed schedules demonstrating steady progress will be made in all areas of work and provides a limit of 15 years to compete all soil investigation work and 20 years to complete all demolition of portions of the facility not used by the project. The Corporate Guarantee provides a further incentive for the Permittee to make progress as that liability may decrease as work is completed. In the view of staff these provisions are reasonable and will provide the County with the ability it does not currently have to enforce site demolition and clean-up. A more aggressive set of requirements would not have been reasonable because many of the idled assets are physically intertwined with active assets, requiring significant planning and work to demolish and remove. Further, allowing adequate time for idled assets to be repurposed or reused meets both private and public objectives. Finally, the amount of demolition and clean-up work is substantial and sufficient time must be allotted to feasibly perform this work.

Soil clean-up work is required by the conditions and the Corporate Guarantee is required to be updated as a result of soil investigations. Condition 5 states,"…the Permittee shall investigate soil conditions at the site and, where necessary, clean-up and restore the site to a condition suitable for commercial and industrial land uses."

Further, conditions 6.c through 6.e relate to the Work Plan and provide as follows:

"(c) The Work Plan must include a schedule for completing the investigation of soil conditions at the site. The soil investigation must be completed no later than 15 years after final approval of the land use permit."

"(d) The Work Plan must include a schedule for restoring the site to a condition suitable for commercial and industrial land uses as determined by the applicable regulatory agencies having oversight of restoration activities."

"(e) The Work Plan must include cost estimates for demolition and removal, and for site investigations and associated potential clean-up."

Finally, condition 7.e provides as follows:

"(e) Within 30 days after the County's approval of the Work Plan and each amended Work Plan, the value of the Corporate Guarantee shall be updated to reflect all updated cost estimates included in the Work Plan or amended Work Plan, as applicable."

It should also be noted that soil and groundwater contamination at the facility is already regulated by the California Department of Toxic Substances Control and the San Francisco Bay Regional Water Quality Control Board, and any new contamination discovered through implementation of the project conditions would also be regulated by these bodies. The proposed conditions are intended to supplement and complement the regulatory work of these agencies.

The value of the Corporate Guarantee will be adjusted at reasonable intervals. The amount will be adjusted annually for inflation in a manner consistent with the financial assurance programs widely employed by agencies regulating soil and groundwater contamination (see condition 5.a). The amount will also be adjusted with the completion of each Work Plan. The Work Plan will be required to be submitted 30 months after issuance of the land use permit and must be updated at least once every five years (see condition 6.f).

The requirement in condition 5 that the Permittee "clean up and restore the site to a condition suitable for commercial and industrial land uses" sets a reasonable minimum standard. It is not clear at this time that a higher standard will be feasible or appropriate. Soil and groundwater cleanup activities regulated by the state typically establish a cleanup standard on a case-by-case basis and are guided by the uses allowed by the current zoning. The proposed conditions are intended to set a consistent standard across the facility that would enable a broad range of commercial and industrial future uses, including various forms of manufacturing, warehousing, retail and office. This is a broader array of potential uses than would be allowed under the current heavy industrial zoning.

Charles Davidson Appeal

The Appellant contends the Project's renewable diesel is not a low-carbon fuel, and that the per barrel carbon intensities will "actually increase significantly (despite the decrease in throughput)", as such the Project is inconsistent with California climate pathways and the Low Carbon Fuel Standard (LCFS). It is further stated this is because the hydro-deoxygenation reaction needed to produce renewable diesel is the most energy-intensive process which requires the Refinery to "greatly expand its hydrogen usage", thereby negating any carbon benefit derived from the Project. In addition, the Appellant states that the "default principal feedstock is expected to be soybean oil" resulting in the use of "33,000 square miles of soybean acreage."

Appeal Point 1. Hydrogen Use

<u>Staff Response</u>

Regarding statements that the Project would actually increase carbon intensities since the proposed processing requires a substantial increase in hydrogen usage are not true. Similar comments were received during the public review period of the Draft EIR and are addressed in detail in Final EIR Master Response No. 5, Renewable Fuels Processing.

In summary, Hydrogen Plant capacity at the Rodeo Refinery is limited by the capacities of the existing Hydrogen Plant (Unit 110) and Air Liquide's facility, which is a third-party supplier of hydrogen to the Rodeo Refinery. The Project does not propose to increase Hydrogen Plant capacity. However, the Draft EIR acknowledges that the Project has the potential to indirectly increase the use of hydrogen that would be supplied by Air Liquide, but also states that this potential increase would not require Air Liquide to increase capacity. The following hydrogen production volumes summarizes information contained in revised Draft EIR Appendix B, Air Quality and Greenhouse Gas Emissions Technical Data, to show the amount of hydrogen production at baseline and post-Project.

<u>Rodeo Refinery Hydrogen Production (Unit 110)</u>
Baseline: 12 million standard cubic feet (scf)/day
Post Project: 22 million scf/day

<u>Air Liquide Hydrogen Production</u>
Baseline: 93.26 million scf/day
Post Project: 120 million scf/day

<u>Baseline vs. Project Totals</u>
Total Baseline: 105.26 scf/day
Total Post Project: 142 scf/day

Total Additional Hydrogen Required by the Project = 36.74 million scuf/day

Appeal Point 2. Climate Pathways and the LCFS

<u>Staff Response</u>

Regarding inconsistency with California's Climate Pathways and the LCFS, as discussed in Draft EIR Section 4.8, Greenhouse Gas Emissions, the Project would result in a reduction in GHG emissions as compared to the 2019 baseline. In addition, and to the point of the Appellant, the emissions evaluation in the Draft EIR conservatively underestimates the GHG emissions reductions from the Project. This is because the GHG reductions resulting from the combustion of renewable fuels as opposed to the combustion of petroleum-based fuels have not been relied upon to determine the Project's impacts to GHG emissions, as the precise amount of the reductions would depend on the feedstocks being used, which as described previously are unknown.

The LCFS is a market-based program that encourages the production of lower carbon intensity (CI) transportation fuels. The CI benchmarks are reduced annually, with a mandate to reduce CI of the transportation fuel pool by 20 percent by 2030. The CI takes into account the life cycle GHG emissions associated with each fuel type.

To comply with the LCFS is one of the Project's main objectives. The Project would cease refining crude oil feedstocks and process renewable feedstocks to generate transportation fuels that have lower carbon intensity (CI) than the gasoline or diesel LCFS baseline fuels. By providing renewable fuel to the supply pool, the Project would support the overall objectives of the LCFS to increase the availability of lower carbon fuels and to lower the CI of the overall transportation fuel pool. Based on the average CI of the renewable diesel sold in California in 2021, the Project would assist California by providing transportation fuels that reduce the lifecycle carbon emissions by approximately 8.5 million metric tons per year.

It is important to note that the Project is one step of many that will need to occur to achieve carbon neutrality - the Project's renewable fuels are intended as part of the state's GHG emissions reduction strategies. Refer to Final EIR Master Response No. 6, Purpose of Project for additional information.

Also see NRDC Appeal Response (g) regarding the LCFS program achieving the State's climate goals. Draft EIR Section 4.8, Greenhouse Gas Emissions, Impact 4.8-3 specifically addresses these, and other regulations related to CI and reducing GHG emissions.

Appeal Point 3. Soybean as "default principal feedstock"

Staff Response

Regarding the statement that soybean oil will be the dominant feedstock by default implies that the Applicant will have no choice but to use soybean oil. This is incorrect. First, the Applicant proposes use of a variety of feedstocks, including soybean oil, and has not proposed or stated to County staff that their intention is to use primarily soybean oil. Second, the feedstock market is highly variable so the precise means types, sources and amounts of feedstocks cannot be known with certainty. Given this uncertainty, it cannot be assumed that soybean oil, or any other single renewable feedstock, will be predominantly used at the Rodeo Refinery. These points are discussed in the Draft EIR Chapter 3, Project Description and supported with technical information provided in Final EIR Master Response No. 4, Land Use and Feedstocks and Master Response No. 5, Renewable Fuels Processing. Also see NRDC Appeal Response (d).

Crockett Community Foundation Appeal

Appeal Point: Appellants contend that "Terms of proposed Community Benefits Agreement were not sufficiently defined."

Staff Response

A draft of the proposed CBA is included in the materials for this hearing. The CBA would grant the County discretion to expend the funds to benefit the community, providing as follows:

"The County shall, in its sole discretion, allocate funds received pursuant to this Agreement to projects and programs that benefit the communities near the Refinery by improving the health, well-being, and quality of life of residents, and that support building and sustaining a strong and resilient local economy and workforce, including the development and implementation of workforce development and training programs to prepare residents for new renewable and clean energy career pathways and jobs."

CONCLUSION

The proposed Phillips 66 Rodeo Renewed Project, with the attached Conditions of Approval, is consistent with the General Plan and the Heavy Industrial zoning designation for the site; all environmental impacts would be mitigated to less-than-significant levels or overriding considerations exist; the health, safety, and general welfare of the public would be preserved; and there would be economic benefits as a result of the project, such as reductions in greenhouse gas emissions, demolition of the Carbon Plant and the Santa Maria refinery, retaining current employment levels, reinvestment in the community, reductions in energy and natural gas usage, and benefits as listed in the project statement of overriding considerations.

Staff recommends that the Board of Supervisors DENY the appellants' appeal, CERTIFY that the EIR was completed in compliance with CEQA, was reviewed and considered by the Board of Supervisors before project approval, and reflects the County's independent judgment and analysis, CERTIFY the EIR, ADOPT the CEQA findings, ADOPT the Mitigation Monitoring and Reporting Program for the project, ADOPT the Statement of Overriding Considerations for the project, DIRECT the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk, SPECIFIY that the Department of Conservation and Development is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based, APPROVE the attached Community Benefits Agreement, and APPROVE the Phillips 66 Rodeo Renewed Project (County File No. CDLP20-02040) based on the attached findings and subject to the attached conditions of approval.

FINDINGS AND CONDITIONS OF APPROVAL FOR THE PHILLIPS 66 RODEO RENEWED PROJECT; PHILLIPS 66 COMPANY (APPLICANT & OWNER); COUNTY FILE# CDLP20-02040

A. GROWTH MANAGEMENT PERFORMANCE STANDARDS

1. **Traffic:** A traffic impact analysis was prepared for the Rodeo Renewed Project which suggested mitigation measures that, if implemented, would reduce any potential impacts on traffic during construction of the project to less-than-significant levels. The project was also reviewed by the Public Works Department and the Department of Conservation and Development, Transportation Planning Section for impacts on traffic and circulation and is subject to compliance with their conditions of approval. The project is also subject to compliance with the mitigation measures identified within the Final Environmental Impact Report. Therefore, the proposed project will not have an adverse impact on traffic in the area.

2. **Water:** Implementation, operation, and maintenance of the project at the Rodeo Refinery and Santa Maria Site would not require new or expanded water facilities. Therefore, the project would not result in an increase in demand for new or expanded water service or facilities, and thus would not cause significant environmental effects. No impact would occur.

3. **Sanitary Sewer:** Although the refinery lies within the Rodeo Sanitary District's service area, the refinery collects, treats, and discharges all wastewater and stormwater to its own on-site wastewater treatment system. Since the refinery does not discharge to the public wastewater treatment facilities, the capacity of the Rodeo Sanitary District's wastewater treatment facility would be unaffected by the project. Implementation, operation, and maintenance of the project at the Rodeo Refinery and Santa Maria Site would not require new or expanded sanitary sewer facilities. Therefore, the project would not result in an increase in demand for new or expanded sanitary sewer service or facilities, and thus would not cause significant environmental effects. No impact would occur.

4. **Fire Protection:** At both the Rodeo Refinery and Santa Maria Site, Phillips 66 currently provides internal fire protection and emergency services with adequate emergency personnel, equipment, and response times. The Rodeo Refinery is licensed by the State Fire Marshal to provide its own fire protection. The refinery is part of a Mutual Aid Organization, which is composed of more than half a dozen refineries that agree to provide one another with emergency response resourced in the event of a major emergency. The Rodeo-Hercules Fire District can also provide emergency services to the refinery; however, the Rodeo-

Hercules Fire District would be supported by the Pinole Fire Department, the Crockett-Carquinez Fire District, and the Contra Costa County Fire Protection District in the event that major assistance was needed at the refinery. Implementation of the Rodeo Renewed Project would require a similar level of protection as under baseline conditions at the Rodeo Refinery and would not increase the demand for fire protection services. Therefore, it is not expected that the project would affect service ratios or response times or increase the use of existing fire protection or emergency facilities such that substantial physical deterioration, alteration, or expansion of these facilities would occur, and it is not expected to require additional support from public fire protection agencies.

5. **Public Protection:** The Growth Management Element standard is 155 square feet of Sheriff's facility/station area and support facilities for every 1,000 members of the population. At both the Rodeo Refinery and Santa Maria Site, Phillips 66 currently provides internal police protection with adequate emergency personnel, equipment, and response times. Construction and demolition related to the project, including the transitional phase, would lead to temporary increases in population. At the Rodeo Refinery, approximately 500 construction workers would be required at its peak over the approximate 21-month construction period, and a smaller number to accomplish demolition at the Santa Maria Site. It is estimated that approximately 80 construction workers would be expected to relocate temporarily to the area, with fewer to the Santa Maria Refinery area. Thus, it is not expected that the project would affect service ratios or response times or increase the use of existing police protection or facilities such that substantial physical deterioration, alteration, or expansion of these facilities would occur, and would not increase the demand for police protection services compared to baseline conditions. No impacts related to police protection would occur.

6. **Parks and Recreation:** The project does not include parks or recreational facilities. Additional parks and recreational facilities would not be necessary as a result of the project. As indicated above in Public Protection, the temporary population increase associated with the construction, demolition, and transitional phases of the project would not be significant, and thus, would not require the construction of parks and recreational facilities. Therefore, no impact would occur related to construction or expansion of recreation facilities.

7. **Flood Control and Drainage:** The project elements would all be constructed within the previously-developed areas, where stormwater and runoff is controlled and treated onsite before discharge; therefore, drainage patterns would not be altered. Furthermore, removal of the Carbon Plant and Santa Maria facilities

would result in a decrease in total impermeable surface area, which will consequently decrease surface runoff levels and would reduce onsite and offsite flooding, as well as reduce the chance for exceedance of stormwater drainage systems. Thus, no impact would occur.

B. LAND USE PERMIT FINDINGS

1. **Required Finding:** *That the proposed conditional land use shall not be detrimental to the health, safety, and general welfare of the county.*

   Project Finding: The Rodeo Renewed Project will modify the existing Rodeo refinery into a repurposed facility that would process renewable feedstocks into renewable diesel fuel, renewable components for blending with other transportation fuels, and renewable fuel gas. The facility would no longer receive or refine petroleum crude oil. Renewable feedstocks are not considered hazardous materials, and the refinery conversion would therefore lessen the volume of hazardous materials being processed at the refinery. An Environmental Impact Report (EIR) was prepared for the project that disclosed the project impacts on the environment including analysis of hazards and hazardous materials. The EIR determined that the repurposed facility would be a cleaner facility and would overall reduce impacts to the community and environment. In addition, the Rodeo refinery includes buffer zones that have been established around the facility to provide a safe-distance barrier between the refinery and the community. The Rodeo site is bounded on the northeast and southeast by undeveloped open space and industrial uses. The southwest edge of the Rodeo site is a 300- to 600-foot undeveloped area that is maintained as a buffer between the Rodeo Refinery and the Bayo Vista residential area of Rodeo. Therefore, based on the forgoing, the project will not be detrimental to health, safety, and general welfare of the County. In addition, the applicant has agreed to enter into a Community Benefits Agreement that provides financial support for workforce training and development and sustainability initiatives within Contra Costa County. This agreement directly supports the general welfare of the County and its residents through the commitment of applicant-provided funding. Furthermore, the applicant is required as a condition of project approval to ensure the long-term reusability of the project site by implementing a work plan for the demolition and cleanup of the refinery site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project is not detrimental to the long-term health, safety, or general welfare of the County or its residents.

2. **Required Finding:** *That the proposed conditional land use shall not adversely affect the orderly development of property within the county.*

   Project Finding: The Rodeo Renewed Project does not include any new land development. The refinery is approximately 1,100 acres in size and is located in the unincorporated area of Rodeo. Interstate Highway 80 (I-80) bisects the refinery in a northeast to southwest direction. All elements of the Rodeo Renewed Project would be located on about one acre within the existing boundaries of the 495-acre portion of refinery property already developed for refining operations. All local elements of the project will be within the portion of the lands designated for Heavy Industry (HI) use by the County General Plan and zoned Heavy Industrial District (H-I) under the Contra Costa County zoning ordinance. Pursuant to these designations, the processing of renewable feedstocks and other manufacturing operations are allowed and are permitted uses. Based on the foregoing, the Rodeo Renewed Project will not adversely affect the orderly development of property with the County. In addition, the project has also been conditioned to ensure the long-term reusability of the project site by implementing a work plan for the demolition and cleanup of the refinery site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project site is not burdened with obsolete equipment and hazardous materials that would prevent or hinder future development in the County.

3. **Required Finding:** *That the proposed conditional land use shall not adversely affect the preservation of property values and the protection of the tax base within the county.*

   Project Finding: The refinery has been in operation at its current location since 1896. The proposed project will be situated within the 495-acre portion of the refinery property already developed for refining operations. The project will not change the refinery's current land use other than switching the refining or renewable feedstocks, nor will it be inconsistent with the present industrial uses in the vicinity of the refinery, including those conducted at the PG&E substation, the Shore Terminal (formerly NuStar) facility, and the Rodeo Sanitary District. The refinery also consists of approximately 600 acres of undeveloped land, a portion of which is used by the refinery as a buffer zone to limit potential impact of the refining operations on non-industrial land uses located in the refinery's general vicinity. Further, implementation of the project would maintain the assessed value of the refinery property, which would allow the facility to continue to contribute to the County's tax base. Thus, the project will not adversely affect the preservation of property values and the protection of the tax base within the County.

4. **Required Finding:** *That the proposed conditional land use shall not adversely affect the policy and goals as set by the general plan.*

   Project Finding: The proposed project is consistent with the overall goals and policies of the General Plan. The Land Use Element supports the manufacture of transportation fuels within the Heavy Industry land use designation. The project also meets the Growth Management Performance Standards section of the General Plan.

5. **Required Finding:** *That the proposed conditional land use shall not create a nuisance and/or enforcement problem within the neighborhood or community.*

   Project Finding: The project will be located on land designated Heavy Industry (HI) by the General Plan, and zoned Heavy Industrial District by the County zoning ordinance. Industrial operations have occurred throughout the refinery property for well over 100 years. The residential development of Bayo Vista and the community of Rodeo are located south of the refinery. The refinery maintains an open space buffer zone between the oil processing areas and the closest sensitive receptors. The Shore Terminal petroleum products storage facility is located directly to the north of the refinery, with the community of Tormey and Crockett as the closest neighborhoods in that direction. However, topographically these communities are physically separated from the refinery by rolling hills. The refinery abuts the San Pablo Bay to the west, with land designated by the General Plan as Open space (OS) to the east. Since the project will be refining renewable feedstocks, it is expected that there will be a decrease in environmental impacts as well as a decrease in the potential for nuisances. In addition, the project has also been conditioned to ensure the long-term reusability of the project site by implementing a work plan for the demolition and cleanup of the refinery site. The condition requires the applicant to provide financial assurances for the removal of obsolete equipment and site remediation of hazardous materials. This assurance and continued effort at cleaning up the site will ensure the project site does not become a nuisance, and also reduces the risk of hazardous materials impacting the surrounding neighborhood or community.

6. **Required Finding:** *That the proposed conditional land use shall not encourage marginal development within the neighborhood.*

Project Finding: The Rodeo Renewed Project will be located in areas zoned Heavy Industrial District (H-I) under the County Zoning Ordinance and designated Heavy Industry (HI) in the General Plan. Most of the undeveloped land adjacent to the 495-acre developed portion of the refinery is maintained by Phillips 66 as open space to serve as a buffer between refining operations and the adjacent non-industrial land uses. The areas to the north and southwest are already developed for industrial use. The refinery will not alter its use of the buffer zone, and the project will maintain the existing land use in a manner that will ensure its continued ability to meet future transportation fuel demands. The proposal will not encourage marginal development within the neighborhood or County.

7. **Required Finding:** *That special conditions or unique characteristics of the subject property and its location or surroundings are established.*

   Project Finding: The Phillips 66 Rodeo refinery has existed in its present location for more than 100 years and is one of the few areas in the County suitable for the proposed project. The project areas are zoned Heavy Industrial District (H-I) by the County Zoning Ordinance. This designation allows the refining of fuel feedstocks and other manufacturing operations.

C. CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) FINDINGS

1. **Environmental Impact Report.** The Rodeo Renewed Project proposes to modify the existing Phillips 66 Rodeo Refinery into a repurposed facility that would process renewable feedstocks into renewable diesel fuel, renewable components for blending with other transportation fuels, and renewable fuel gas. The project includes constructing a pre-treatment facility, modifying certain existing refinery equipment, taking other existing processing equipment out of service, demolishing an existing petroleum coke facility on the Rodeo refinery site, demolishing the Santa Maria Refinery in San Luis Obispo County, and decommissioning several hundred miles of regional pipelines. As a result of the project, the Rodeo facility would no longer refine crude oil into petroleum-based products.

   The Department of Conservation and Development determined that an environmental impact report (EIR) was required for the project. Accordingly, the County prepared an EIR for the project (State Clearinghouse# 2020120330). The project EIR includes a Draft EIR and Final EIR. The Final EIR provides responses to comments received on the Draft EIR during the public comment period. The Notice of Preparation of the EIR was posted on December 21, 2020, and a public

Scoping Meeting was held on January 20, 2021. Both written and oral comments were received during the public comment period and the Scoping Meeting; the Scoping Meeting comments were responded to in the Draft EIR, which was released for public review on October 18, 2021, with a Notice of Availability. A 60-day comment period for the Draft EIR began on October 18, 2021, and ended December 17, 2021. During the comment period, the County received 86 comment letters on the Draft EIR and over 1,600 form letters both for and against the proposed project. The principal comment topics included marine vessel safety, spills of feedstocks and products, process safety, traffic congestion, the CEQA baseline, greenhouse gas emissions, and indirect impacts on agriculture and land use.

The County's Reponses to Comments received are provided in the Final EIR that has been prepared for the project. The Final EIR also includes County-initiated updates and errata to the Draft EIR. These errata constitute minor text changes to the Draft EIR and occur in the Executive Summary; Chapter 1 Introduction; Chapter 3 Project Description; Section 4.3 Air Quality; Section 4.4 Biological Resources; Section 4.5 Cultural Resources; Section 4.7 Geology and Soils; Section 4.8 Greenhouse Gas Emissions; Section 4.9 Hazards and Hazardous Materials; Section 4.10 Hydrology and Water Quality; Section 4.14 Tribal Cultural Resources; Chapter 5 Alternatives; Section 6.4 Cumulative Impacts; and Appendix B. The complete text of the changes can be found in Chapter 4 in the Final EIR. The changes were made primarily to correct grammatical and typographical errors, as well as to improve accuracy and readability of certain passages. The text changes are not the result of any new significant information or adverse environmental impact, do not alter the effectiveness of any mitigation included in the pertinent section, and do not alter any findings in the Draft EIR.

2. **Findings Regarding Potential Environmental Impacts**

Contra Costa County is the lead agency under the California Environmental Quality Act (CEQA) for preparation, review, and certification of the EIR for the Phillips 66 Rodeo Refinery Renewable Fuels Project. As the lead agency, the County is also responsible for determining the potential environmental impacts of the proposed action, which of those impacts are significant, and which impacts can be mitigated through imposition of feasible mitigation measures to avoid or minimize such impacts to a level of "less than significant." The EIR for the project considered the project's impacts, which are summarized in Table ES-3 of the Draft EIR.

Pursuant to Public Resources Code Section 21081 and CEQA Guidelines Section

15091, no public agency shall approve and carry out a project where an EIR has been certified, which identifies one or more significant impacts on the environment that would occur if the project is approved, unless the public agency makes one or more findings for each of those significant impacts, accompanied by a brief explanation of the rationale for each finding. The possible findings, which must be supported by substantial evidence in the record, are:

- Changes or alterations have been required in, or incorporated into, the project that mitigate or avoid the significant impact on the environment.

- Changes or alterations are within the responsibility and jurisdiction of another public agency and have been, or can and should be, adopted by that other agency.

- Specific economic, legal, social, technological or other considerations make infeasible the mitigation measures or project alternatives identified in the EIR.

"<u>No Impact" or "Less than Significant Impact</u>"

FINDING: The project would have either no impacts or less than significant impacts related to:

- Aesthetics
- Energy conservation
- Greenhouse gases
- Land use and planning
- Noise and vibration
- Wildfires.

FINDING: Potentially significant impacts were also identified, all of which can be mitigated to a less-than-significant level. These impacts affect the environmental topics of:

- Air Quality
- Biological Resources
- Cultural Resources
- Geology and Soils
- Transportation and Traffic
- Tribal Cultural Resources

Environmental analysis contained in the EIR determined that measures were available to mitigate these potential adverse impacts to less-than-significant levels. The recommended mitigation measures are included within the Mitigation Monitoring and Reporting Plan, which describes the timing and responsible agency for monitoring compliance with all mitigation measures. The mitigation measures have also been incorporated into the recommended conditions of approval.

FINDING: The EIR for the proposed project identified eight significant and unavoidable impacts related to related to

- Air quality
- Biology
- Hazards and hazardous materials
- Hydrology and water quality

Each impact is described further below. These potential environmental impacts remain significant and unavoidable despite the imposition of all feasible mitigation measure.

The County determines and finds that changes or alterations have been required in, or incorporated into, the Project which avoid or substantially lessen the significant environmental effects as identified in the EIR. The County also determines and finds that all feasible mitigation has been adopted to reduce or avoid the potentially significant impacts identified in the FEIR and that no additional feasible mitigation is available to further reduce significant impacts.

3. **Findings on Alternatives to the Phillips 66 Rodeo Renewed Project**

<u>Alternatives Considered but Eliminated from Further Consideration</u>

The County finds that each of the alternatives eliminated from further consideration in the Draft EIR is infeasible, would not meet most project objectives, and/or would not reduce or avoid significant impacts of the Project, for the reasons detailed in Chapter 5 of the Draft EIR.

<u>Alternatives Analyzed in the EIR</u>

In accordance with CEQA and the CEQA Guidelines, Chapter 5 of the Draft EIR evaluated a reasonable range of alternatives to the Phillips 66 Rodeo Renewed Project. The EIR's analysis examined the feasibility of each alternative, the environmental impacts of each alternative, and each alternative's ability to meet the project objectives described in Chapter 5, Section 5.5 of the Draft EIR. In accordance with CEQA and the CEQA Guidelines, the alternatives analysis included an analysis of a no-project alternative and identified the Reduced Project Alternative as the environmentally superior alternative.

FINDING: The County certifies that it has independently reviewed and considered the information on alternatives provided in the Draft EIR and in the administrative record. For the reasons set forth below, the County finds that the alternatives either fail to avoid or substantially lessen the Project's significant impacts (and in some cases increase or create new significant and unavoidable impacts) or are "infeasible" as that term is defined by CEQA and the CEQA Guidelines.

The Draft EIR evaluated four alternatives to the Project:

- Alternative 1 – No Project Alternative
- Alternative 2 – Reduced Project Alternative
- Alternative 3 – Terminal Only Alternative
- Alternative 4 – No Temporary Increase in Crude Oil Alternative

Brief summaries of these alternatives and findings regarding these alternatives are provided below.

1) Alternative 1 – No Project Alternative

   Under the No Project Alternative, the Rodeo Refinery would continue to receive petroleum-based feedstocks, including crude oil, by pipeline (from the Santa Maria Site via the Pipeline Sites) and marine vessels, refine those feedstocks into a variety of petroleum-based fuel products, and ship those products out by pipeline, marine vessels, and rail. The Carbon Plant would continue to receive raw coke by truck, produce finished petroleum coke, and ship that material to market by rail and truck. The No Project Alternative would consist of the continued operation of the existing Rodeo Refinery equipment and the Santa Maria Site and the Pipeline Site. Future activity levels would be, on average, similar to the baseline in terms of material throughput, number of truck, train, and marine vessel trips, and employment. (See Draft EIR, Chapter 5, Section 5.5.1.1)

   FINDING: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the No Project alternative infeasible. This alternative would not achieve most of the objectives of the proposed project, with the exception of maintaining quality jobs. Moreover, the No Project Alternative would result in the same impacts to aesthetics, biological resources, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, and public services as the proposed Phillips 66 Rodeo Renewed Project and would result in more severe impacts to air quality, energy use, greenhouse gas emissions, transportation, and utilities and service systems than the proposed Phillips 66 Rodeo Renewed Project. For these reasons, the County rejects this alternative.

2) Alternative 2 – Reduced Project Alternative

In the Reduced Project Alternative, the capacity of the Rodeo Renewed facility would be reduced compared to the Project because the Pre-Treatment Unit would consist of only two pre-treatment trains instead of three, thereby reducing overall processing capability for renewable feedstocks to 55,000 bpd (instead of 80,000 bpd) and shipping 50,000 bpd of renewable fuels (instead of 55,000 bpd). With existing (as of 2021) renewable processing capacity of 12,000 bpd (i.e., the Unit 250 production) and the reduced shipping of 50,000 bpd, the total production capacity of the facility after the Reduced Project Alternative is operational would be 62,000 bpd of renewable fuels. Like the Project, the facility would continue to receive 38,000 bpd of gasoline blendstocks, and blend and ship 40,000 bpd conventional fuels. All other elements of the Reduced Project would be identical to the Project, including demolition of the Carbon Plant and the Santa Maria Site and cleaning and decommissioning the Pipeline Sites. (See Draft EIR, Chapter 5, Section 5.5.2.1)

<u>FINDING</u>: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the Reduced Project Alternative infeasible. By reducing renewable feedstock throughput, this alternative would generate fewer jobs, would result in a lower volume of renewable fuels being produced and brought to market to support the State's renewable energy goals, and would not achieve the Project objectives as well as the proposed project. For these reasons, the County rejects the Reduced Project Alternative as infeasible.

3) Alternative 3 – Terminal Only Alternative

Under the Terminal Only Alternative, the process equipment at the Rodeo Site would be demolished, likely over a period of years, leaving only the storage tankage and associated infrastructure, including the wastewater treatment plant (Unit 100), piping, pumps, and administration buildings in active service. In this alternative, as in the Project, the Carbon Plant and Santa Maria Site would be closed and demolished and the Pipeline Sites would be cleaned and removed from active service.

Operation of this alternative would involve the receipt of gasoline blendstocks, as under existing conditions, as well as renewable fuels and blendstocks, by marine vessel and potentially rail. Finished gasoline and diesel, both petroleum-based and renewable, would be distributed from the Rodeo Site by pipeline and potentially rail. The Terminal Only Alternative would result in 110 vessels per year delivering blendstocks and fuels, which is considerably less than the Project. As described in Table 5-1, the Terminal Only Alternative is assumed to handle an average of 75,000 bpd, in approximately equal amounts of gasoline and diesel fuel. This alternative would employ far fewer personnel than the Project, with employment estimated at 75. (See Draft EIR, Chapter 5, Section 5.5.3.1)

<u>FINDING</u>: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, render the Terminal Only Alternative infeasible. The Terminal Only Alternative would not convert the Rodeo Refinery to a renewable transportation fuels production facility. The Terminal Only Alternative would not produce renewable fuels, and would therefore not assist California in meeting its goals for renewable energy, GHG emission reductions and reduced Carbon Intensity. The lack of production of renewable fuels at the Rodeo facility could mean that the region's fuel demand would have to be met with greater amounts of petroleum-based fuels, some portion of it imported, than with the Project. In that case, the Terminal Only Alternative would not assist in the attainment of California's climate and energy goals. The Terminal Only Alternative would not convert equipment and infrastructure to produce renewable fuels, but it would discontinue the processing of crude oil at the Rodeo Refinery. The Terminal Only Alternative would result in the elimination of approximately 575 of the 650 existing jobs at the Rodeo Refinery. Although it would preserve 75 jobs.

The Terminal Only Alternative would repurpose and reuse only a small portion of the facility's existing equipment capacity, primarily storage tanks and administrative facilities. The remainder of the refinery's equipment would not be reused.

The Terminal Only Alternative would preserve marine and rail facilities, and possibly truck loading/offloading facilities. Those facilities would likely be used to receive, store, and distribute renewable fuels and would certainly be used to handle conventional fuels and fuel components (e.g., the existing gasoline blending operation). However, this alternative does not include accessing renewable feedstocks.

The Terminal Only Alternative would not be able to process renewable feedstocks.

The Terminal Only Alternative would allow the Rodeo facility to supply regional market demand for conventional and renewable fuels. However, the capacity to supply fuels would be substantially less than the Project's and would not maintain the facility's current capacity to produce approximately 120,000 bpd.

The Terminal Only Alternative would not transition the Rodeo Refinery to a renewable fuels facility and would not require any increased crude oil or gasoil deliveries.

The Terminal Only Alternative would not have the capacity to process recyclable fats, oil, and grease.

The Terminal Only Alternative would provide a mechanism for compliance with the federal RFS and state LCFS because it would likely supply some renewable and low-carbon fuels, although to a far lesser extent than the Project.

For these reasons, this alternative was found to be infeasible.

4) Alternative 4 – No Temporary Increase in Crude Oil Alternative

Under this alternative, it is reasonable to expect that the decreased vessel traffic to the Marine Terminal during the 7-month interim period, and therefore the decreased production of refined products by the Rodeo Refinery, would be offset by imports to other regional fuels facilities and possibly, where feasible, increased production by the other three regional refineries. Imports would likely come primarily by vessel, and increased production, should some excess capacity be available, would require imports of crude oil, also likely primarily by marine vessel. Accordingly, some or all of the vessel traffic that would not come to the Rodeo facility would come to other regional facilities.

Under operating conditions, however, the No Temporary Increase in Crude Oil Alternative would result in the same significant and unavoidable impacts associated with vessel spills as the Project.

FINDINGS: In accordance with Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3), the County finds that specific legal, social, technological, or other considerations, including failure to meet project objectives, renders the No Temporary Increase in Crude Oil Alternative infeasible. Under this alternative, it is reasonable to expect that the decreased vessel traffic to the Marine Terminal during the 7-month interim period, and therefore the decreased production of refined products by the Rodeo Refinery, would be offset by imports to other regional fuels facilities and possibly, where feasible, increased production by the other three regional refineries. Imports would likely come primarily by vessel, as happened in 2020 during the Marathon Martinez refinery shutdown (CEC, 2021a), and increased production, should some excess capacity be available, would require imports of crude oil, also likely primarily by marine vessel. Accordingly, some or all of the vessel traffic that would not come to the Rodeo facility would come to other regional facilities.

Under operating conditions, however, the No Temporary Increase in Crude Oil Alternative would result in the same significant and unavoidable impacts associated with vessel spills as the Project.

The No Temporary Increase in Crude Oil Alternative would convert the Rodeo Refinery to a renewable transportation production facility that would produce the same amounts of renewable fuels as the Project.

The No Temporary Increase in Crude Oil Alternative would produce renewable fuels in the same quantities as the Project. Accordingly, the facility would assist California in meeting its goals for renewable energy, GHG emission reductions, and reduced CI. The decreased production of conventional fuels during the construction period compared to the Project would mean that the region's fuel demand would have to be met with imported petroleum-based fuels, but such an eventuality would be of short duration (7 months) and would not interfere with the long-term supply of renewable fuels.

The No Temporary Increase in Crude Oil Alternative would result in the conversion of equipment and infrastructure to produce renewable fuels to the same extent as the Project would, and it would discontinue the processing of crude oil at the Rodeo Refinery.

The No Temporary Increase in Crude Oil Alternative would preserve the existing jobs.

The No Temporary Increase in Crude Oil Alternative would repurpose and reuse the facility's existing equipment capacity, including the marine and rail terminals to the same extent as the Project.

The No Temporary Increase in Crude Oil Alternative would preserve marine, rail, and truck offloading facilities to access renewable feedstocks to the same extent as the Project.

The No Temporary Increase in Crude Oil Alternative would have the same ability to process a comprehensive range of renewable feedstocks as the Project.

The No Temporary Increase in Crude Oil Alternative would maintain the Rodeo facility's capacity to supply regional market demand for both renewable and conventional fuels in the long term. However, during 7 months of the construction period, the Rodeo facility would not be able to supply its historic share of the regional market for conventional fuels, which could result in either increased imports or regional shortages of transportation fuels.

The No Temporary Increase in Crude Oil Alternative would have the capacity to process recyclable fats, oil, and grease.

The No Temporary Increase in Crude Oil Alternative would provide a mechanism for compliance with the federal RFS and state LCFS by producing renewable fuels at the maximum capacity of the Project.

For these reasons, this alternative was found to be infeasible.

5) Environmentally Superior Alternative

FINDING: While the County finds that the Reduced Project Alternative is the environmentally superior alternative because it would not result in impacts greater than the proposed Project and would in many cases result in reduced impacts compared to the proposed Project, the County also finds that the Reduced Project Alternative is infeasible under Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3) because it would not meet many of the basis project objectives. The Reduced Project Alternative is infeasible because it would result in a lower volume of renewable fuels being brought to market to support the State's renewable energy goals, and would not achieve the Project objectives as well as the proposed project. For these reasons, the County rejects the environmentally superior alternative as infeasible. The County further finds that of the remaining alternatives evaluated in the EIR, each has varying levels of impacts on different environmental resources, as noted in the Findings above, and none of the remaining alternatives is superior to the Project for CEQA purposes. Compared to the remaining alternatives, the Phillips 66 Rodeo Renewed Project provides the best available and feasible balance between maximizing attainment of the project objectives and minimizing significant environmental impacts, and the Project is the environmentally superior alternative among those options.

4. **Statement of Overriding Considerations.**

Pursuant to Public Resources Code section 21081(b), the County must balance the benefits of the proposed project against any unavoidable environmental impacts in determining whether to approve the proposed project, and CEQA Guidelines section 15093(b) provides that when a public agency approves a project that will result in significant impacts that are identified in the Final EIR but are not avoided or substantially lessened, the agency must state in writing the specific reasons to support its decision based on the Final EIR and/or other information in the whole administrative record. If the specific economic, legal, social, technological, or other benefits of a proposed project outweigh its unavoidable adverse environmental impacts, the adverse effects may be considered "acceptable." If a lead agency makes a statement of overriding considerations, the statement should be included in the record of the project approval and should be mentioned in the notice of determination. The statement of overriding considerations does not substitute for, and is in addition to, findings required by CEQA Guidelines section 15091.

The project would have significant and unavoidable impacts (i.e., impacts that would remain significant even after the application of mitigation) related to air quality, biology, hazards and hazardous materials, and hydrology and water quality. Specifically:

1) The project would have a significant and unavoidable air quality impact from the rail transport of renewable feedstocks.

2) The project would have significant and unavoidable impacts on special-status species, wetlands, and migratory wildlife from potential spills from marine vessels and the introduction of invasive species.
3) The project would have a significant and unavoidable impact as a result of the hazards posed by potential spills of hazardous materials from marine vessels.
4) The project would have a significant and unavoidable impact on surface water quality from potential spills from marine vessels.

Contra Costa County is the lead agency under the California Environmental Quality Act (CEQA) for preparation, review, and certification of the EIR for the Rodeo Renewed Project. As the lead agency, the County is also responsible for determining the potential environmental impacts of the proposed action, which of those impacts are significant, and which impacts can be mitigated through imposition of feasible mitigation measures to avoid or minimize such impacts to a level of "less than significant." Public Resources Code section 21081(a) provides that no public agency may approve or carry out a project for which an EIR has been certified that identifies one or more significant effects on the environment that would occur if the project is approved or carried out, unless the public agency makes findings with respect to each significant effect.

A. <u>Summary of Significant Unavoidable Environmental Impacts</u>

The EIR for the proposed project identified eight significant and unavoidable impacts related to related to air quality, biology, hazards and hazardous materials, and hydrology and water quality, including :<u>Impact 4.2-3</u>: The EIR discloses that locomotive emissions along rail lines outside the San Francisco Bay Area Air Basin (SFBAAB) related to transport of renewable feedstocks for the Rodeo Renewed Project would exceed regulatory significance thresholds, resulting in a significant impact. Furthermore, the EIR discloses that the County has no authority to impose mitigation measures based on federal preemption, even if any were feasible, on that activity. Accordingly impacts would be significant and unavoidable.

<u>Impact 4.4-4</u>: The EIR discloses that marine vessels transiting San Francisco and San Pablo bays and unloading and loading at the marine terminal could potentially spill crude oil and refined products during the transitional period and renewable feedstocks and renewable products during the operational period and that such spills would constitute a significant impact on special-status species and their habitats. The EIR imposes mitigation measures BIO-2

and BIO-3, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.4-5</u>: The EIR discloses that marine vessel activity during the transitional and operational periods would increase the risk of introducing non-indigenous invasive species, resulting in a significant impact on sensitive species and their habitats. The EIR imposes mitigation measures BIO-4a and BIO-4b, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.4-7</u>: The EIR discloses that marine vessel activity during the transitional and operational periods would increase the risk of spills of crude oil and refined products during the transitional period and renewable feedstocks and products during the operational period. These effects would constitute a significant impact on sensitive species and their habitats. The EIR imposes mitigation measure BIO-5, but discloses that the measure would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.4-9</u>: The EIR discloses that marine vessels transiting San Francisco and San Pablo bays and unloading and loading at the marine terminal could spill crude oil and refined products during the transitional period and renewable feedstocks and renewable products during the operational period and that such spills would constitute a significant impact on native resident and migratory wildlife. The EIR imposes mitigation measure BIO-6, but discloses that the measure would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.4-10</u>: The EIR discloses that marine vessel activity during the transitional and operational periods would increase the risk of introducing non-indigenous invasive species, resulting in a significant impact on native resident and migratory wildlife. The EIR imposes mitigation measure BIO-7, but discloses that the measure would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.9-2</u>: The EIR discloses that marine vessels transiting San Francisco and San Pablo bays and unloading and loading at the marine terminal could

potentially spill crude oil and refined products during the transitional period and renewable feedstocks and renewable products during the operational period and that such spills would constitute a significant impact from the risk of spills and the release of hazardous materials. The EIR imposes mitigation measures HAZ-1 and HAZ-2, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

<u>Impact 4.10-1</u>: The EIR discloses that marine vessels transiting San Francisco and San Pablo bays and unloading and loading at the marine terminal could potentially spill crude oil and refined products during the transitional period and renewable feedstocks and renewable products during the operational period and that such spills would constitute a significant impact on surface water quality. The EIR imposes mitigation measures HAZ-1 and HAZ-2, but discloses that those measures would be unlikely to mitigate the project's impact to a less-than-significant level, and impacts would be significant and unavoidable.

B. <u>Overriding Considerations</u>

In addition to reviewing the project EIR in accordance with CEQA requirements, the Commission has reviewed written and oral testimony regarding the aspects of the project, some of which are unrelated to adequacy of the CEQA analysis. Specifically, a wide range of individuals, business entities, and organizations expressed support for the project, pointing out its employment benefits to Contra Costa County, its wider economic benefits to the Bay Area, and its air quality, energy, and carbon-reduction benefits to California. Letters in support of the project were received from, among many others, the United Steelworkers, the International Brotherhood of Electrical Workers, the Contra Costa Building and Construction Trades Council, the Bay Planning Coalition, the Carpenters and Joiners of America, the Industrial Association of Contra Costa County, the East Bay Leadership Council, the Bay Front Chamber of Commerce, the Phillips 66 Community Advisory Panel, Southwest Airlines, and the Council of Business and Industry. A number of individuals expressed their disapproval of the project, primarily on the grounds of potential noise, odors, and risks from the Rodeo Renewed facility itself and potential global land use and food security implications of the increased use of renewable feedstocks.

As required under Public Resources Code section 21081 and CEQA Guidelines section 15093, the County Planning Commission, having reviewed and considered the project EIR, all other written materials within the administrative record, and all oral testimony presented at public hearings and other public meetings on the project EIR, has balanced the benefits of the proposed project against the identified unavoidable adverse impacts associated with the project, and hereby finds that the benefits outweigh and override the significant unavoidable impacts for the reasons set forth below.

After balancing the specific economic, legal, social, technological, and other benefits of the proposed project, the County Planning Commission finds that the significant and unavoidable adverse impacts identified above are acceptable due to the following specific considerations in the record, which outweigh the unavoidable, adverse environmental impacts of the project. Further, the County Planning Commission finds that each of the separate benefits of the proposed project is hereby determined to be, independent of the other proposed project benefits, a basis for overriding all unavoidable environmental impacts identified in the EIR.

The County finds that the project will provide the following benefits to the residents of the County and of the State of California.

<u>Attainment of Regulatory and Policy Goals</u>: The Rodeo Renewed Project transforms an existing crude oil production facility into a renewable fuels processing facility providing for the production of up to 55,000 barrels of renewable transportation fuels per day to assist California in meeting a number of goals. The project's renewable fuels products would produce fewer lifecycle GHG emissions per barrel, and their use in transportation would have a lower carbon footprint than conventional petroleum-based fuels.

- *<u>Assist Attainment of Goals</u>.* Governor Newsom's Executive Order N-79-20 states: "clean renewable fuels play a role as California transitions to a decarbonized transportation sector" and "to support the transition away from fossil fuels consistent with the goals established in this Order and California's goal to achieve carbon neutrality by no later than 2045, the California Environmental Protection Agency and the California Natural Resources Agency, in consultation with other State, local and federal agencies, shall expedite regulatory processes to repurpose and transition upstream and downstream oil production facilities…" The Governor's Order also directs CARB to "develop and propose strategies to continue the State's current efforts to reduce the carbon intensity of fuels beyond 2030 with consideration of the full life cycle of carbon. Additionally, the California Air Resources Board's November 19, 2020, "California's Greenhouse Gas Goals and Deep Decarbonization" presentation anticipates that biofuels will comprise 19 percent of the transportation "fuel" sector by 2045." As a major producer of renewable fuels, the project would materially contribute to California's efforts to meet the goals of Executive Order N-79-20.

- *Compliance With Federal and State Standards*. The federal Renewable Fuel Standard (RFS) program was created under the Energy Policy Act of 2005 as an amendment to the Clean Air Act (CAA), and expanded by the Energy Independence and Security Act of 2007. EPA implements the program in consultation with U.S. departments of Agriculture and Energy. The RFS requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel. The program has a goal of producing, nationally, 36 billion gallons of total renewable fuel per year; by producing over 800 million gallons of renewable fuels per year the project would materially promote that goal.

Under California Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006, refineries are subject to regulations aimed at reducing California's global warming emissions and transitioning to a sustainable, low-carbon future (CARB 2021). The latest Update to the Climate Change Scoping Plan (CARB 2017) sets goals of a 40-percent GHG emission reduction below 1990 emission levels by 2030 and a substantial advancement toward the 2050 goal to reduce emissions by 80 percent below 1990 emission levels. Key provisions of AB 32 include the Low-Carbon Fuel Standard, which is intended to reduce California's dependency on petroleum by encouraging the provision of low-carbon and renewable alternative fuels, and the Cap-and-Trade Regulation, which discourages major sources of GHG emissions and encourages investment in cleaner, more efficient technologies. By increasing production of renewable fuels, the project will provide a mechanism for compliance with these provisions through providing facilities in California.

Furthermore, by reducing emissions of air pollutants from existing conditions, the project will forward the goals of the Bay Area Air Quality Management District's 2017 Clean Air Plan. Specifically, the project would be consistent with the plan's Refinery Emissions Reduction Strategy by eliminating sources associated with petroleum refining, and with the plan's call for refineries to transition to clean energy companies by 2050.

Reductions in Greenhouse Gas Emissions from the Combustion of Renewable Fuels: The combustion of renewable fuels produced by the project would result in reductions of greenhouse gas emissions of approximately 45-75 percent as compared to petroleum-based fuels. Based on the carbon intensity of the renewable diesel sold in California in 2021, the project would reduce the lifecycle carbon emissions of transportation fuels by approximately 8.5 million metric tons per year. (Final EIR, p. 3-50.)

Maintaining Current Employment Levels: Numerous letters of support for the project were received during the comment period from labor unions and individuals citing the retention of family-wage jobs and the creation of construction jobs as key benefits of the project. The project will preserve and protect approximately 650 existing family-wage jobs in Contra Costa County and will continue to provide indirect support to thousands of other jobs in the Bay Area. In addition, construction of the project will provide up to 500 construction jobs.

Sustainability and Reinvestment in Community: The Rodeo Renewed Project is a substantial investment in the community and facility and supports sustainability by re-using and transforming an existing industrial facility and by producing renewable transportation fuels.

Transportation Fuel Supply Security: Interruptions in the regional supply of transportation fuels have occurred as a result of refinery shutdowns for various reasons. These incidents have adversely affected Contra Costa County's residents and businesses through inconvenience and higher fuel prices. A reliable supply of fuels is thus essential for the economic well-being of the region. The project will maintain the Rodeo facility's current capacity to supply regional market demand for transportation fuels by producing up to 67,000 barrels of renewable fuels per day and distributing up to 40,000 barrels of conventional gasoline per day. Furthermore, shortages that could result from a refinery shut-down during construction of the project will not occur because the project will continue to import and refine crude oil during the project construction period.

Recycling Benefits: Recycling organic wastes and by-products such as used cooking oils, rendering wastes, and other fats, oils, and greases has a number of environmental and financial benefits. These include reducing demand on landfill space, reducing the carbon footprint of fuels, and generating a second revenue stream from the same material. These benefits improve quality of life and help businesses thrive. By accepting large quantities of recyclable fats, oils, and grease to be processed into renewable fuels, the project will help Contra Costa County, the region, and the State of California realize those benefits.

Demolition of Santa Maria Refinery and Carbon Plant: The project provides for the demolition of these two sites, eliminating uncertainty regarding the re-use of these sites as currently developed.

Reduction of Truck Traffic near Rodeo: Rodeo Refinery truck traffic in 2019 consisted of approximately 40,000 roundtrips per year. With the Rodeo Renewed Project, including the elimination of truck traffic from the Carbon Plant, truck traffic would be reduced to approximately 16,000 truck roundtrips per year.

Reductions in Energy Usage (Electricity and Natural Gas): The proposed Project would result in modest reductions in electricity usage and substantial reductions in natural gas usage.

Each of these benefits are sufficient to outweigh the adverse environmental impacts of the proposed Project and to justify approval of the project and certification of the EIR.

5. **Certification of EIR**

On the basis of the whole record before it, including the Draft and Final EIRs, and in accordance with Section 15090, the County Planning Commission finds that:

- The EIR has been completed in compliance with CEQA;
- The EIR reflects the County's independent judgement and analysis;
- The EIR was presented to the decision-making body of the Lead Agency and the decision-making body reviewed and considered the information contained in the EIR prior to approving the project.

Pursuant to CEQA Section 15097, a Mitigation Monitoring Program has been prepared, based on the identified impacts and mitigation measures in the EIR. The Mitigation Monitoring Program is intended to ensure that the mitigation measures identified in the EIR are implemented. All mitigation measures are included in the Conditions of Approval for the project.

Recirculation is Not Required

Pursuant to CEQA Guidelines Section 15088.5(a), recirculation of a Draft EIR is required only if:

> *"1) a new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented;*
> *2) a substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance;*
> *3) a feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it; or*
> *4) the draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded."*

None of the text edits or changes to the Draft EIR meet any of the above conditions. Therefore, recirculation of any part of the Draft EIR is not required. The information presented in the project EIR support this determination by the County.

Differences of Opinion Regarding Environmental Analysis

In making its determination to certify the EIR and to approve the project, the Commission recognizes that the project involves controversial environmental issues and that a range of technical and scientific opinion exists with respect to those issues. The Commission has acquired an understanding of the range of this technical and scientific opinion by its review of the Draft EIR, the comments received on the Draft EIR and the responses to those comments in the Final EIR, as well as other testimony, letters, and reports submitted for the record. The Commission recognizes that some of the comments submitted on the EIR, and at the hearing, disagree with the conclusions, analysis, methodology and factual bases stated in the EIR. The EIR was prepared by experts, and that some of these comments were from experts, thus creating a disagreement among experts. The

Commission has reviewed and considered, as a whole, the evidence and analysis presented in the EIR and in the record, and has gained a comprehensive and well-rounded understanding of the environmental issues presented by the project. In turn, this understanding has enabled the Commission to make its decisions after weighing and considering the various viewpoints on these important issues.

Documents and Records

The various documents and other materials constitute the record upon which the Commission bases these findings and the approvals contained herein. These findings cite specific pieces of evidence, but none of the Commission's findings are based solely on those pieces of evidence. These findings are adopted based upon the entire record, and the Commission intends to rely upon all supporting evidence in the record for each of its findings. The location and custodian of the documents and materials that comprise the record is Contra Costa County, Department of Conservation and Development, 30 Muir Road, Martinez, CA, 94553, telephone (925) 655-2705.

CONDITIONS OF APPROVAL FOR THE PHILLIPS 66 RODEO RENEWED PROJECT; PHILLIPS 66 COMPANY (APPLICANT & OWNER); COUNTY FILE# CDLP20-02040

Project Approval

1. Land Use Permit #CDLP20-02040 for the Rodeo Renewed Project is **APPROVED** based on the project materials submitted to the Department of Conservation and Development, Community Development Division (CDD) on August 13, 2020, including the following Documents:
   - Project application, received on August 13, 2020.
   - Rodeo Renewed project description, received on August 13, 2020.
   - Project Draft EIR and Final EIR, dated October 2021 and March 2022 respectively.

This approval is subject to the Conditions of Approval enumerated below**.**

Application Fees

2. The application was subject to an initial deposit of $5,662.00. The application is subject to time and material costs if the application review expenses exceed the initial deposit. Any additional fee due must be paid prior to an application for a grading or building permit, or 60 days of the effective date of this permit, whichever occurs first. The fees include costs through permit issuance and final file preparation. Pursuant to Contra Costa County Board of Supervisors Resolution Number 2019/553, where a fee payment is over 60 days past due, the Department of Conservation and Development may seek a court judgement against the applicant and will charge interest at a rate of ten percent (10%) from the date of judgement. The applicant may obtain current costs by contacting the project planner. A bill will be mailed to the applicant shortly after permit issuance in the event that additional fees are due.

Indemnification Agreement

3. The applicant shall enter into an Indemnification Agreement with the County, and the applicant shall indemnify, defend (with counsel reasonably acceptable to the County), and hold harmless the County, its boards, commissions, officers, employees, and agents (collectively "County Parties") from any and all claims, costs, losses, actions, fees, liabilities, expenses, and damages (collectively, "Liabilities") arising from or related to the project, the applicant's land use permit application, the County's discretionary approvals for the project, including but not limited to the County's actions pursuant to the California Environmental Quality Act and planning and zoning laws, or the construction and operation of

the project, regardless of whether those Liabilities accrue before or after project approval.

Compliance Report

4. At least 60 days prior to commencement of construction-related activities, issuance of grading permits or issuance of building permits, whichever occurs first, Phillips 66 shall submit an application for Condition of Approval Compliance Review to the CDD. Submittals for this application shall include a report addressing compliance with each condition of approval. The report shall detail how each condition will satisfied and should be accompanied with applicable materials (e.g., documentation, plans, photographs, etc.) that confirm compliance with the permit conditions. This application will remain active throughout the life of the project and additional submittals will be required to ensure compliance with each phase of development (i.e., grading, building). The initial deposit for review of the compliance report is $2,000 and shall be billed for additional time and materials costs that may exceed the initial deposit. The applicant shall also provide an additional deposit of $10,000.00 to cover costs of mitigation monitoring (subject to time and materials costs). Phillips 66 shall be responsible for providing adequate funding to cover all eventual costs of mitigation monitoring.

Demolition & Site Clean-Up/Reuse Program

5. The Permittee shall demolish and remove all portions of the facility that will not be used for any phase of the Project or any intended future use of the facility. Upon the permanent closure of the facility, the Permittee shall demolish and remove all remaining portions of the facility. During the operation of the Project, the Permittee shall investigate soil conditions at the site and, where necessary, clean-up and restore the site to a condition suitable for commercial and industrial land uses. To assure the performance of these requirements, the Permittee shall do all of the following:

    (a) Within 30 days following final approval of the land use permit, the Permittee shall provide a Corporate Guarantee to Contra Costa County to guarantee the performance and implementation of all tasks specified in the Demolition and Site Clean-Up/Reuse Work Plan (Work Plan). The initial value of the Corporate Guarantee shall be no less than $100,000,000, based on estimated costs as described in Table A in Condition 7 below. The Corporate Guarantee shall be adjusted annually for inflation by March 15 of each year following project approval. The inflation adjustment shall be calculated using the inflation factor in Title 27, California Code of Regulations, Section 22236, for the prior calendar year. Following any adjustment to the value of the Corporate Guarantee pursuant to Condition 7, then the Corporate Guarantee shall be adjusted annually for inflation in accordance with this subsection, except that no inflation adjustment shall be required for a year in which the value of a Corporate Guarantee was adjusted between January 1 and March 15 based on an updated cost estimate.

(b) The following portions of the facility shall be demolished and removed as follows:

(1) The Contra Costa Carbon Plant shall be demolished and removed no later than two years following the commencement of operations of the Project.

(2) The process units that have operating permits relinquished as part of the Project, such as Crude Unit 267, Sulfur Plant 236 and Sulfur Plant 238 shall be demolished and removed within 5 years of permanent cessation of operations in the respective process units.

(c) Within 30 months following final approval of the land use permit, the Permittee shall submit a Work Plan as specified in Condition 6 for review and reasonable approval by the Contra Costa County Conservation and Development Director or designee.

Site Clean-Up/Reuse Work Plan Elements

6. The Work Plan must include all of the following information:

(a) The Work Plan must specify which portions of the facility will be demolished and removed from the site over time. The Work Plan must include a description of all above-ground and below-ground structures, equipment, and appurtenances that will be demolished and removed from the site.

(b) The Work Plan must include the following schedules. Each schedule must propose a phased completion plan demonstrating steady progress by including all interim tasks necessary to demolish and remove each portion of the facility, and the estimated time necessary to complete each task.

(1) A schedule for removal of all portions of the facility that will not be used for any phase of the Project or any intended future use of the facility. All demolition and removal activities included in this schedule must be completed no later than 20 years after approval of the Work Plan.

(2) A schedule for completing the demolition and removal of all remaining portions of the facility upon the permanent closure of the facility.

(c) The Work Plan must include a schedule for completing the investigation of soil conditions at the site. The soil investigation must be completed no later than 15 years after final approval of the land use permit.

(d) The Work Plan must include a schedule for restoring the site to a condition suitable for commercial and industrial land uses as determined by the applicable regulatory agencies having oversight of restoration activities.

(e) The Work Plan must include cost estimates for demolition and removal, and for site investigations and associated potential clean-up.

(f) At least once every five years, the Permittee shall submit an amended Work Plan for review and reasonable approval by the Contra Costa County Conservation and Development Director or designee. The amended Work Plan shall include the information specified in subsections (a) through (e) of Condition 6, and include the following additional information:

(1) A description of all demolition and clean-up tasks and activities completed following the submission of the prior Work Plan, and the status of in-progress Work Plan tasks and activities.

(2) An accounting of actual expenditures on all demolition and clean-up tasks and activities completed under the initial Work Plan and all amended Work Plans.

(3) A schedule of all demolition and clean-up tasks and activities that are expected to be implemented in the next five-year period.

(g) The Permittee shall comply with all applicable federal, state, and local laws and regulations when performing all demolition and clean-up tasks and activities at the site.

Corporate Guarantee

7. The Corporate Guarantee required by Condition 5 must comply with the following requirements.

   (a) The Guarantor must be:

      (1) A parent corporation of the Permittee; or

      (2) An entity whose parent corporation is also the parent corporation of Permittee; or

      (3) An entity that is engaged in a substantial contractual business relationship with the Permittee and issues the Corporate Guarantee as an act incident to that business relationship.

   (b) The Guarantor must meet the following financial means test based on the Guarantor's audited year-end financial statements:

      (1) A current rating for its most recent bond issuance of AAA, AA, A, or BBB, issued by Standard & Poor's, or Aaa, Aa, A, or Baa, issued by Moody's; and

      (2) Tangible net worth at least six times the sum of the current cost estimate covered by the Corporate Guarantee; and

      (3) Tangible net worth of at least $15 million; and

      (4) Assets located in the United States amounting to at least 90 percent of its total assets or at least six times the sum of the current cost estimate covered by the corporate guarantee.

   (c) The Corporate Guarantee shall be substantially in the form attached as Appendix A, subject to reasonable approval by Contra Costa County.

   (d) If the Guarantor fails to meet the requirements of the financial means test under Condition 7 or wishes to terminate the Corporate Guarantee, the Guarantor shall send notice of the failure or intent to terminate by certified mail to Permittee and Contra Costa County within 90 days after the end of the financial reporting year in which the failure or intent to terminate occurs.

The Corporate Guarantee shall terminate no less than 60 days after the date that Permittee and Contra Costa County have received notice of failure or intent to terminate, as evidenced by the return receipts. Subject to reasonable approval by Contra Costa County, the Guarantor shall establish alternate coverage on behalf of Permittee, or Permittee shall establish alternate coverage, within 60 days after the County's receipt of notice of failure or intent to terminate.

Table A – Initial Corporate Guarantee Basis

Activity	Estimated Costs ($Millions)
Net Demolition Costs for Idled and Operating Assets	$ 70
Estimated Site Investigation & Non-Determined Clean-up or Other Costs held in Reserve	$ 30
Total	$ 100

(e) Within 30 days after the County's approval of the Work Plan and each amended Work Plan, the value of the Corporate Guarantee shall be updated to reflect all updated cost estimates included in the Work Plan or amended Work Plan, as applicable.

(f) Subject to reasonable approval by Contra Costa County, the value of the Corporate Guarantee may be adjusted to reflect:

(1) Completion of demolition activities that have occurred; and

(2) Completion of site investigation or other activities that have occurred as set forth in the Work Plan.

(3) Changes in estimates or defined work scope as it relates to any changes to demolition, clean-up, or site investigation activities.

(g) The portion of the Corporate Guarantee for Estimated Site Investigation & Non-Determined Clean-up or Other Costs (in Table A) shall maintain a minimum of $15 million held in reserve until site investigation activities are complete, which amount shall not be subject to adjustment for inflation.

Definitions Relating to the Demolition & Site Clean-Up/Reuse Program

8. For purposes of Conditions 5 through 7 above, the following terms have the following meanings:

(a) "Facility" means all structures, processing equipment, and other equipment and appurtenances used for manufacturing, storage, or distribution at the Rodeo refinery located at 1380 San Pablo Ave, Rodeo, CA 94572 and the Carbon Plant located at 2101 Franklin Canyon Rd, Rodeo, CA 94572.

(b) "Project" means the Phillips 66 Rodeo Renewed Project, County File (CDLP20-02040).

(c) "Site" means the real property where the Rodeo refinery is located, at 1380 San Pablo Ave, Rodeo, CA 94572, and the Carbon Plant located at 2101 Franklin Canyon Rd, Rodeo, CA 94572.

Timing for Carbon Plant Removal

9. The Contra Costa Carbon Plant shall be demolished and removed no later than two years following the commencement of operations of the project.

Community Benefits Agreement

10. The applicant has agreed to enter into a Community Benefits Agreement with the County to implement the permittee's planned Community Benefit Initiative for the Project. The agreement will detail the benefit(s) that the Project will provide the community and an implementation schedule for the agreed-upon community benefits. At least 30-days prior to scheduling of a final building permit inspection for this project (e.g., occupation of the subject site), the permittee shall provide CDD staff with evidence that the permittee and County have entered into a Community Benefits Agreement.

CONSTRUCTION MANAGEMENT CONDITIONS

Construction Hours

11. Non-emergency maintenance, construction and other activities on the site related to this use shall be prohibited on State and Federal holidays on the calendar dates that these holidays are observed by the State or Federal government as listed below:

- New Year's Day (State and Federal)
- Birthday of Martin Luther King, Jr. (State and Federal)

- Washington's Birthday (Federal)
- Lincoln's Birthday (State)
- President's Day (State)
- Cesar Chavez Day (State)
- Memorial Day (State and Federal)
- Juneteenth National Independence Holiday (Federal)
- Independence Day (State and Federal)
- Labor Day (State and Federal)
- Columbus Day (Federal)
- Veterans Day (State and Federal)
- Thanksgiving Day (State and Federal)
- Day after Thanksgiving (State)
- Christmas Day (State and Federal)

For specific details on the actual days and dates that these holidays occur, please visit the following websites:
Federal Holidays - www.federalreserve.gov/aboutthefed/k8.htm
California Holidays - www.sos.ca.gov/holidays.htm

Contact Persons and Information

12. Prior to commencement of construction-related activities, issuance of grading permits or issuance of building permits, whichever occurs first, Phillips 66 shall post a publicly visible sign stating the names, titles, and phone numbers of individuals responsible for control of construction noise, dust, litter, and traffic. A 24-hour emergency number shall also be stated. The sign shall be kept up to date and shall be placed in a conspicuous location on refinery property along San Pablo Avenue.

Construction Trailers

13. Phillips 66 may locate construction trailers onsite. Such trailers may be located onsite for up to two months prior to the start of project construction and must be removed within two months after construction is complete.

Community Outreach

14. In order to help support the local economy, Phillips 66 shall encourage its employees and subcontractors to patronize local businesses and restaurants during breaks and mealtimes, and that they use personal vehicles during these

break times and not construction equipment, such as dump trucks or other large construction vehicles, so as to minimize unnecessary road wear by heavy trucks on local roadways.

MITIGATION MEASURES REQUIRED FOR COMPLIANCE WITH THE CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

These conditions are mitigation measures identified in the project's Environmental Impact Report.

(Air Quality Mitigation Measure AQ-1) - Implement Bay Area Air Quality Management District (BAAQMD) Basic Control Measures

15. Construction contractors shall implement the following applicable BAAQMD basic control measures as best management practices (BMPs):

    - All exposed surfaces (e.g., parking areas, staging areas, soil piles, graded areas, and unpaved access roads) shall be watered two times per day.
    - All haul trucks transporting soil, sand, or other loose material offsite shall be covered.
    - The permittee shall not cause or allow track-out at any active exit from the site onto an adjacent paved public roadway or shoulder of a paved public roadway that exceeds cumulative 25 linear feet and creates fugitive dust visible emissions. All visible mud or dirt track-out onto adjacent public roads shall be removed using wet power vacuum street sweepers within 4 hours of when the owner/operator identifies such excessive track-out on San Pablo Avenue, between the refinery and Interstate 80, and on the access roads between the Carbon Plant and Highway 4. The use of dry power sweeping is prohibited.
    - All vehicle speeds on unpaved roads shall be limited to 15 miles per hour.
    - All roadways, driveways, and sidewalks to be paved shall be completed as soon as possible. Building pads shall be laid as soon as possible after grading unless seeding or soil binders are used.
    - Idling times shall be minimized either by shutting equipment off when not in use or reducing the maximum idling time to 2 minutes as recommended by the BAAQMD, and not to exceed 5 minutes as required by the California airborne toxics control measure Title 13, Section 2485 of the California Code of Regulations (CCR). Clear

signage shall be provided for construction workers at all access points.

- Monitor the extent of the trackout at each active exit from the site onto a paved public road at least twice during each workday, at times when vehicle traffic exiting the site is most likely to create an accumulation of trackout, or as otherwise specified by the Air District.
- Document the active exit locations monitored each workday.
- Document each occasion when the trackout exceeds cumulative 25 linear feet and all trackout control and cleanup actions initiated as a result of the above monitoring.
- Maintain these records for at least five years, in electronic, paper hard copy or log book format, and make them available to the Air District upon request.
- All construction equipment shall be maintained and properly tuned in accordance with manufacturer's specifications.
- All equipment shall be checked by a certified mechanic and determined to be running in proper condition prior to operation.
- Post a publicly visible sign with the telephone number and person to contact at the Lead Agency regarding dust complaints. This person shall respond and take corrective action within 48 hours. The Air District's phone number shall also be visible to ensure compliance with applicable regulations.

Construction contractors shall implement the following Advanced Construction Mitigation Measures:

- All exposed surfaces shall be watered at a frequency adequate to maintain minimum soil moisture of 12 percent. Moisture content can be verified by lab samples or moisture probe.
- All excavation, grading, and/or demolition activities shall be suspended when average wind speeds exceed 20 mph.
- Wind breaks (e.g., trees, fences) shall be installed on the windward side(s) of actively disturbed areas of construction. Wind breaks should have at maximum 50 percent air porosity.
- Vegetative ground cover (e.g., fast-germinating native grass seed) shall be planted in disturbed areas as soon as possible and watered appropriately until vegetation is established.
- The simultaneous occurrence of excavation, grading, and ground-disturbing construction activities on the same area at any one time

shall be limited. Activities shall be phased to reduce the amount of disturbed surfaces at any one time.

- All trucks and equipment, including their tires, shall be washed off prior to leaving the site.
- Site accesses to a distance of 100 feet from the paved road shall be treated with a 6- to 12-inch compacted layer of wood chips, mulch, or gravel.
- Sandbags or other erosion control measures shall be installed to prevent silt runoff to public roadways from sites with a slope greater than one percent.

(Air Quality Mitigation Measure AQ-2) - Implement a NOx Mitigation Plan

16. Phillips 66 shall prepare a NOx Mitigation Plan (NM Plan) prior to the issuance of construction-related permits for site preparation. The purpose of the NM Plan is to document expected construction and transitional phase NOx emissions in detail; and, if necessary, to identify feasible and practicable contemporaneous measures to reduce aggregated construction and transition NOx emissions to below the BAAQMD's 54 pounds per day threshold of significance.

    The NOx emissions estimate for the project shall include consideration of readily available NOx construction and transition emission reduction measures, and/or other emission reduction actions that shall be implemented during construction and transitional phase of the project. The NM Plan shall describe the approximate amount of NOx emissions reductions that will be associated with each action and reduction measure on a best estimate basis.

    The NM Plan shall be submitted to the Contra Costa County Department of Conservation and Development and the BAAQMD for review and approval, or conditional approval based on a determination of whether the NM Plan meets the conditions described below. The NM Plan shall include those recommended measures listed below needed to reduce the project's construction and transition NOx emissions to less than the BAAQMD's threshold of significance.

    The NM Plan shall include a detailed description of the NOx emissions for all construction and transition activities based on BMPs and use data at the time of project approval and current estimation protocols and methods. The plan shall, at a minimum, include the following elements:

(1) Project Construction and Transition NOx Emissions
The project's construction and transition NOx emission estimates presented in the NM Plan will be based on the emission factors for off-road and on-road mobile sources used during construction and transition, over and above baseline, along with the incorporation of vehicle fleet emission standards. Project construction and transition NOx emission estimates will be based upon the final Project design, project-specific traffic generation estimates, equipment to be used onsite and during transition, and other emission factors appropriate for the project prior to construction. The methodology will generally follow the approach used in the Draft EIR and in Appendix B.

(2) NOx Emission Reduction Measures
The NM Plan shall include feasible and practicable NOx emission reduction measures that reduce or contemporaneously offset the project's incremental NOx emissions below the threshold of significance. Planned emission reduction measures shall be verifiable and quantifiable during project construction and transitional phase. The NM Plan shall be consistent with current applicable regulatory requirements. Measures shall be implemented as needed to achieve the significance threshold and considered in the following order: (a) onsite measures, and (b) offsite measures within the San Francisco Bay Area Air Basin. Feasible onsite and offsite measures must be implemented before banked emissions offsets (emission reduction credits) are considered in the NM Plan.

a. Recommended Onsite Emission Reduction Measures:
   i. Onsite equipment and vehicle idling and/or daily operating hour curtailments;
   ii. Construction "clean fleet" using Tier 4 construction equipment to the maximum extent practicable;
   iii. Reductions in vessel and/or rail traffic;
   iv. Other onsite NOx reduction measures (e.g., add-on NOx emission controls); or
   v. Avoid the use of Suezmax vessels to the maximum extent practicable.
   vi. To the maximum extent practicable, all off-road equipment shall use the highest tier engines available when zero emissions equipment is not available (e.g., Tier 4 construction, rail, marine vessels and equipment, including for any dredging activities). In

place of Tier 4 engines, offroad equipment can incorporate retrofits such that emission reductions achieved equal or exceed that of a Tier 4 engine.

Contra Costa County Department of Conservation and Development in its consideration of the NM Plan shall have the option to require daily NOx reductions at the Carbon Plant necessary to achieve the NOx daily emissions significance threshold. Daily idling of one kiln would provide sufficient NOx reductions to offset the Project's incremental NOx emissions to below the NOx daily emissions threshold of significance on individual days that construction emissions are estimated to potentially be above the daily NOx significance threshold.

Additional measures and technology to reduce NOx emissions may become available during the Project construction and operation period. Such measures may include new energy systems (such as battery storage) to replace natural gas use, new transportation systems (such as electric vehicles or equipment) to reduce fossil-fueled vehicles, or other technology (such as alternatively-fueled emergency generators or renewable backup energy supply) that is not currently available at the project-level. As provided in the NM Plan, should such measures and technology become available and be necessary to further reduce emissions to below significance thresholds, Phillips 66 shall demonstrate to the Contra Costa County Department of Conservation and Development and BAAQMD satisfaction that such measures are as, or more, effective as the existing measures described above.

b. <u>Recommended Offsite Emission Reduction Measures</u>:
Phillips 66, with the oversight of the Contra Costa County Department of Conservation and Development and BAAQMD, shall reduce emissions of NOx by directly funding or implementing a NOx control project (program) within the San Francisco Bay Area Air Basin to achieve an annual reduction equivalent to the total estimated construction NOx emission reductions needed to lower the project's NOx impact below the 54 pound per day significance threshold. The offsite measures will be based on the NOx reductions necessary after consideration of onsite measures.

To qualify under this mitigation measure, the NOx control project must result in emission reductions within the San Francisco Bay Area Air Basin that would not otherwise be achieved through compliance with existing regulatory requirements or other program participation. Phillips 66 shall notify Contra Costa County within six months of completion of the NOx control project for verification.

(3) Quarterly Verification Reports
Phillips 66 shall prepare and submit NM Verification Reports quarterly during the construction or transitional phase activities, while project construction or transitional phase activities at the site are ongoing. The reporting period will extend through the last year of construction. The purpose of the report is to verify and document that the total project construction and transitional phase NOx emissions for the previous year, based on appropriate emissions factors for that year and the effectiveness of emission reduction measures, were implemented.

The report shall also show whether additional onsite and offsite emission reduction measures, or additional NOx controls, would be needed to bring the project below the threshold of significance for the current year. The report shall be prepared by Phillips 66 and submitted to the Contra Costa County Department of Conservation and Development and the BAAQMD for review and verification. NOx offsets for the previous year, if required, shall be in place by the end of the subsequent reporting year. If Contra Costa County and the BAAQMD determine the report is reasonably accurate, they can approve the report; otherwise, Contra Costa County and/or the BAAQMD shall identify deficiencies and direct Phillips 66 to correct and re-submit the report for approval.

(Air Quality Mitigation Measure AQ-4) - Odor Prevention & Management Plan

17. Phillips 66 shall develop and implement an Odor Prevention & Management Plan (OPMP). The OPMP shall be an integrated part of daily operations at the Rodeo site, to effect diligent identification and remediation of any potential odors generated by the facility.
    - The OPMP shall be developed and reviewed by the County in consultation with the BAAQMD prior to operation of the project

and implemented upon commencement of the renewable fuels processes.

- The OPMP shall be an "evergreen" document that provides continuous evaluation of the overall system performance, identifying any trends to provide an opportunity for improvements to the plan, and updating the odor management and control strategies as necessary.
- The OPMP shall include guidance for the proactive identification and documentation of odors through routine employee observations, routine operational inspections, and odor compliant investigations.
- All odor complaints received by the facility shall be investigated as soon as is practical within the confines of proper safety protocols and site logistics. The goal of the investigation will be to determine if an odor originates from the facility and, if so, to determine the specific source and cause of the odor, and then to remediate the odor.
- The OPMP shall be retained at the facility for Contra Costa County, the BAAQMD, or other government agency inspection upon request.

(Biological Mitigation Measure BIO-1a) – Update Pre-Arrival Documents

18. Phillips 66 shall update pre-arrival document materials and instructions sent to tank vessels agents/operators scheduled to arrive at the Marine Terminal with the following information and requests:

    - Available outreach materials regarding the Blue Whales and Blue Skies incentive program.

    - Whale strike outreach materials and collision reporting from NMFS.

    - Request extra vigilance by ship crews upon entering the Traffic Separation Scheme shipping lanes approaching San Francisco Bay and departing San Francisco Bay to aid in detection and avoidance of ship strike collisions with whales.

    - Request compliance to the maximum extent feasible (based on vessel safety) with the 10 knot voluntary speed reduction zone.

    - Encourage participation in the Blue Whales and Blue Skies incentive program.

(Biological Mitigation Measure BIO-1b) – California Department of Fish and Wildlife (CDFW) and Research Sturgeon Support

19. Phillips 66 will conduct and support the following activities to further the understanding of vessel strike vulnerability of sturgeon in San Francisco and San Pablo Bay. Coordinate with CDFW and Research Sturgeon to ensure appropriate messaging on information flyers suitable for display at bait and tackle shops, boat rentals, fuel docks, fishing piers, ferry stations, dockside businesses, etc. to briefly introduce interesting facts about the sturgeon and research being conducted to learn more about its requirements and how the public's observations can inform strategies being developed to improve fisheries habitat within the estuary.

(Biological Mitigation Measure BIO-3) - Update and Review Facility Response Plan and Spill Prevention, Control, and Countermeasure Plan with Office of Spill Prevention & Response (OSPR)

20. The Facility Response Plan and Spill Prevention, Control, and Countermeasure (SPCC) Plan shall be updated to address the project operational changes, including changes in proposed feedstocks and types of vessels and trips. The SPCC shall address the operational changes of the Transitional Phase and post-project. Phillips 66 will consult with OSPR during update of the SPCC Plan, especially adequacy of booms at the Marine Terminal to quickly contain a spill of renewable feedstocks.
    In accordance with CCR Title 14, Chapter 3, Subchapter 3, several types of drills are required at specified intervals. Due to the potential for rapid dispersion of biofuels and oils under high energy conditions, Phillips 66 shall increase the frequency of the following drills to increase preparedness for quick response and site-specific deployment of equipment under different environmental conditions.

    - Semi-annual equipment deployment drills to test the deployment of facility-owned equipment, which shall include immediate containment strategies, are required on a semiannual pass/fail basis – if there is fail during first six months, then another drill is required. Phillips 66 will require that both semi-annual drills are conducted and schedule them under different tide conditions.

- An Oil Spill Removal Organization (OSRO) field equipment deployment drill for on-water recovery is required at least once every three years. Phillips will increase the frequency of this drill to annual.

- CDFW-OSPR shall be provided an opportunity to help design, attend and evaluate all equipment deployment drills and tabletop exercises. To ensure this, Phillips 66 shall schedule annual drills during the first quarter of each year to ensure a spot on OSPR's calendar.

(Biological Mitigation Measure BIO-4a) - Prohibit Ballast Water Exchange

21. Phillips 66 shall prohibit vessels from ballast water exchange at the Marine Terminal.

(Biological Mitigation Measure BIO-4b) - Update Pre-Arrival Documentation

22. Phillips 66 shall update pre-arrival document materials and instructions sent to tank vessels agents/operators to ensure they are advised prior to vessel departure of California's Marine Invasive Species Act and implementing regulations pertinent to (1) ballast water management, and (2) biofouling management. Additionally, Phillips 66 will request that vessel operations provide documentation of compliance with regulatory requirements (e.g., copy of ballast water management forms and logs of hull husbandry cleaning/inspections).

(Cultural Mitigation Measure CUL-1) - Inadvertent Discovery of Archaeological Resources

23. Pursuant to CEQA Guidelines Section 15064.5(f), "provisions for historical or unique archaeological resources accidentally discovered during construction" shall be instituted. In the event that any cultural resources are discovered during ground-disturbing activities, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the County and a qualified archaeologist (as approved by the County) to assess the significance of the find pursuant to CEQA Guidelines Section 15064.5. If cultural resources are recovered on State lands, submerged or tidal lands, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the California State Lands Commission. If any find is determined to be significant, representatives of the County and the

qualified archaeologist would meet to determine the appropriate course of action.

Avoidance is always the preferred course of action for archaeological sites. In considering any suggestion proposed by the consulting archaeologist to reduce impacts to archaeological resources, the County would determine whether avoidance is feasible in light of factors such as the nature of the find, project design, costs, and other considerations. If avoidance is infeasible, other appropriate measures (e.g., data recovery, interpretation of finds in a public venue) would be instituted. Work may proceed on other parts of the Project site while mitigation for archaeological resources is carried out. All significant cultural materials recovered shall be, at the discretion of the consulting archaeologist, subject to scientific analysis, professional museum curation, and documented according to current professional standards.

(Cultural Mitigation Measure CUL-2) - Inadvertent Discovery of Human Remains

24. The treatment of human remains and associated or unassociated funerary objects discovered during any ground-disturbing activity shall comply with applicable state law. Project personnel shall be alerted to the possibility of encountering human remains during project implementation, and apprised of the proper procedures to follow in the event they are found. State law requires immediate notification of the County coroner, in the event of the coroner's determination that the human remains are Native American, notification of the California Native American Heritage Commission (NAHC), which would appoint a Most Likely Descendent (MLD) (PRC Section 5097.98). The MLD would make all reasonable efforts to develop an agreement for the treatment, with appropriate dignity, of human remains and associated or unassociated funerary objects (CEQA Guidelines Section 15064.5[d]).

    The agreement shall take into consideration the appropriate excavation, removal, recordation, analysis, custodianship, curation, and final disposition of the human remains and associated or unassociated funerary objects. The PRC allows 48 hours to reach agreement on these matters. If the MLD and the other parties do not agree on the treatment and disposition of the remains and funerary objects, Phillips 66 shall follow PRC Section 5097.98(b), which states that "the landowner or his or her authorized representative shall reinter the human remains and items associated with Native American burials with appropriate dignity on the property in a location not subject to further subsurface disturbance."

(Geology & Soils Mitigation Measure GEO-1) - Comply with Geotechnical Report

25. Phillips 66 shall comply with and implement all of the following measures designed to reduce potential substantial adverse effects resulting from strong seismic ground shaking:

    - A California licensed geotechnical engineer or engineering geologist shall perform a comprehensive geotechnical investigation of all project facilities based on adequate subsurface exploration, laboratory testing of selected samples, and engineering/geologic analysis of the data gathered. The information shall be compiled and presented as a geotechnical report that provides an evaluation of potential seismic and geologic hazards, including secondary seismic ground failures, and other geologic hazards, such as landslides, expansive and corrosive soils, and provides current California Building Code seismic design parameters, along with providing specific standards and criteria for site grading, drainage, berm, and foundation design.

    - For construction requiring excavations, such as foundations, appropriate support and protection measures shall be implemented to maintain the stability of excavations and to protect construction worker safety. Where excavations are adjacent to existing structures, utilities, or other features that may be adversely affected by potential ground movements, bracing, underpinning, or other methods of support for the affected facilities shall be implemented.

    - Recommendations in the approved geotechnical report shall be incorporated into the design and construction specifications and shall be implemented during build-out of the project.

    - The project geotechnical engineer shall provide observation and testing services during grading and foundation-related work, and shall submit a grading completion report to the County prior to requesting the final inspection. This report shall provide full documentation of the geotechnical monitoring services provided during construction, including the testing results of the American Society for Testing and Materials. The Final Grading Report shall also certify compliance of the as-built Project with the recommendations in the approved geotechnical report.

(Hazards and Water Quality Mitigation Measure HAZ-1) - Implement Release, Monitoring and Avoidance Systems

The following actions shall be completed by Phillips 66 prior to project operations, including the transitional phase, and shall include routine inspection, testing and maintenance of all equipment and systems conducted in accordance with manufacturers' recommendations and industry guidance for effective maintenance of critical equipment at the Marine Terminal. Feedstocks handled at the Marine Terminal are not regulated under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) (e.g. renewable feedstocks such as soybean oil and tallow) and therefore not subject to OSPR oversight, and are also not subject to the California State Lands Commission (CSLC) oversight efforts (Marine Oil Terminal and Maintenance Standards (MOTEMS), Article 5, Article 5.3 and Article 5.5, depending on the materials handled). Yet materials may be detrimental to the environment if spilled. Regulated products (i.e. "Oil" and "Renewable Fuels" defined in Pub. Resources Code sec. 8750) will continue to be transferred at the Marine Terminal, which do require MOTEMS-compliant Terminal Operating Limits for those products that reside within the jurisdiction of the CSLC. To ensure that project operation continues to meet those standards, the following measures are required.

26. Applicability of MOTEMS, Article 5, 5.3, 5.5 and Spill Prevention Requirements.

As some materials transferred at the terminal may be feedstocks or other non-regulated materials/feedstocks/products, Phillips 66 shall comply with the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) for all vessels calling at the Marine Terminal regardless of feedstock/material type. In addition, MOTEMs operational regulations, as codified in Article 5. Marine Terminals Inspection and Monitoring (2CCR §2300 et seq), Article 5.3 Marine Terminals Personnel Training and Certification (2CCR §2540 et seq), and Article 5.5 Marine Terminals Oil Pipelines (2CCR §2560 et seq), including items such as static liquid pressure testing of pipelines, shall be implemented for all operations at the Marine Terminal regardless of feedstock/material type and LKS Act regulatory status.

Upon request, Phillips 66 shall provide evidence to relevant regulatory agencies that these facilities, operational response plans, and other applicable measures have been inspected and approved by CSLC and OSPR and determined to be in compliance.

If terminal operations do not allow for regular compliance and inspection of LKS and MOTEMS requirements by the CSLC and OSPR, Philips 66 shall employ a CSLC-approved third-party to provide oversight as needed to ensure the same level of compliance as a petroleum-handling facility, and to ensure maximum protection of the environment from potential spills and resulting impacts. Phillips 66 shall provide evidence of compliance upon request of relevant regulatory agencies.

27. Remote Release Systems

The Marine Terminal has a remote release system that can be activated from a single control panel or at each quick-release mooring hook set. The central control system can be switched on in case of an emergency necessitating a single release of all mooring lines. However, to further minimize the potential for accident releases the following is required:

- Provide and maintain mooring line quick release devices that shall have the ability to be activated within 60 seconds.
- These devices shall be capable of being engaged by electric/push button release mechanism and by integrated remotely-operated release system.
- Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).
- Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.
- In consultation with the CSLC and prior to project operation, Phillips 66 shall provide a written evaluation of their existing equipment and provide recommendations for upgrading equipment to meet up-to-date best achievable technology standards and best industry practices, including but not limited to consideration of equipment updates and operational effectiveness (e.g. visual and audible alarm options, data display location and functionality, optional system features). Phillips 66 shall follow guidance provided by

SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4.

- Best achievable technology shall address:
  - Functionality - Controlled release of the mooring lines (i.e. a single control system where each line can be remotely released individually in a controlled order and succession) vs. release all (i.e. a single control system where all lines are released simultaneously via a single push button). See SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.2.1.
  - Layout - The location(s) of the single control panel and/or central control system to validate that it is operationally manned such that the remote release systems can actually be activated within 60 seconds.

This measure would allow a vessel to leave the Marine Terminal as quickly as possible in the event of an emergency (fire, explosion, accident, or tsunami that could lead to a spill). In the event of a fire, tsunami, explosion, or other emergency, quick release of the mooring lines within 60 seconds would allow the vessel to quickly leave the Marine Terminal, which could help prevent damage to the Marine Terminal and vessel and avoid and/or minimize spills. This may also help isolate an emergency situation, such as a fire or explosion, from spreading between the Marine Terminal and vessel, thereby reducing spill potential. The above would only be performed in a situation where transfer connections were already removed and immediate release would not further endanger terminal, vessel and personnel.

28. Tension Monitoring Systems

- Provide and maintain Tension Monitoring Systems to effectively monitor all mooring line and environmental loads, and avoid excessive tension or slack line conditions that could result in damage to the Marine Terminal structure and/or equipment and/or vessel mooring line failures.

- Line tensions and environmental data shall be integrated into systems that record and relay all critical data in real time to the control room, Marine Terminal operator(s) and vessel operator(s).

- All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM (e.g. vessels are berthing within the MOTEMS compliant speed and angle requirements), and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing).

- System shall include, but not be limited to, quick release hooks only (with load cells), site-specific current meter(s), site-specific anemometer(s), and visual and audible alarms that can support effective preset limits and shall be able to record and store monitoring data.

- Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).

- Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.

- Install alternate technology that provides an equivalent level of protection.

- All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis.

The Marine Terminal is located in a high-velocity current area and currently has only limited devices to monitor mooring line strain and integrated environmental conditions. Updated MOTEMS Terminal Operating Limits (TOLs), including breasting and mooring, provide mooring requirements and operability limits that account for the conditions at the terminal. The upgrade to devices with monitoring capabilities can warn operators of the development of dangerous mooring situations, allowing time to take corrective action and minimize the potential for the parting of mooring lines, which can quickly escalate to the breaking of hose connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a petroleum product spill. Backed up by an alarm system, real-time data monitoring and control room information would provide the Terminal

Person-In-Charge with immediate knowledge of whether safe operating limits of the moorings are being exceeded. Mooring adjustments can be then made to reduce the risk of damage and accidental conditions.

29. Allision Avoidance Systems

- Provide and maintain Allision Avoidance Systems (AASs) at the Marine Terminal to prevent damage to the pier/wharf and/or vessel during docking and berthing operations. Integrate AASs with Tension Monitoring Systems such that all data collected are available in the Control Room and to Marine Terminal operator(s) at all times and vessel operator(s) during berthing operations. The AASs shall also be able to record and store monitoring data.

- All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing).

- Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s).

- Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide", are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives.

- Velocity monitoring equipment is required to monitor reduced berthing velocities until permanent MOTEMS-compliant corrective actions are implemented.

- The systems shall also be utilized to monitor for vessel motion (i.e. surge and sway) during breasting/mooring operations to ensure excessive surge and sway are not incurred.

The Marine Terminal has a continuously manned marine interface operation monitoring all aspects of the marine interface. The Automatic Identification System is monitored through TerminalSmart and provides a record of vessel movements. Pursuant to the CSLC January 26, 2022 letter entitled Phillips 66 (P66) Rodeo Marine Terminal – Review of New

September 2021 Mooring & Berthing Analyses and Terminal Operating Limits (TOLS), the single cone fenders shall not be used as the first point of contact during berthing operations. Therefore, all berthing operations shall utilize the double cone fenders. P66 shall incorporate TOL diagrams with landing point statements in the Terminal Information Booklet. For all vessels, a Phillips 66 Marine Advisor is in attendance and is in radio contact with the vessel master and pilot prior to berthing, reviewing initial contact point and then monitoring.

Excessive surge or sway of vessels (motion parallel or perpendicular to the wharf, respectively), and/or passing vessel forces may result in sudden shifts/redistribution of mooring forces through the mooring lines. This can quickly escalate to the failure of mooring lines, breaking of loading arm connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a spill. Monitoring these factors will ensure that all vessels can safely berth at the Marine Terminal and comply with the standards required in the MOTEMS.

(Traffic/Transportation Mitigation Measure TRA-1) - Implement a Traffic Management Plan

30. Prior to issuance of grading and building permits, Phillips 66 shall submit a Traffic Management Plan for review and approval by the Contra Costa County Public Works Department. At a minimum the following shall be included:

    - The Traffic Management Plan shall be prepared in accordance with the most current California Manual on Uniform Traffic Control Devices, and will be subject to periodic review by the Contra Costa County Public Works Department throughout the life of all construction and demolition phases.

    - Truck drivers shall be notified of and required to use the most direct route between the site and the freeway.

    - All site ingress and egress shall occur only at the main driveways to the project site.

    - Construction vehicles shall be monitored and controlled by flaggers.

    - If during periodic review the Contra Costa County Public Works Department, or the Department of Conservation and Development, determines the Traffic Management Plan requires modification, Phillips 66 shall revise the Traffic Management Plan to meet the specifications of Contra Costa County to address any identified issues. This may include such actions as traffic signal modifications, staggered work hours, or other measures deemed appropriate by the Public Works Department.

- If required, Phillips 66 shall obtain the appropriate permits from Caltrans and the Contra Costa County Public Works Department for the movement of oversized or excessive load vehicles on state-administered highways or County maintained roads respectively.

(Tribal Cultural Resources Mitigation Measure TCR-1) - Awareness Training

31. A consultant and construction worker tribal cultural resources awareness brochure and training program for all personnel involved in project implementation shall be developed by Phillips 66 in coordination with interested Native American Tribes (i.e. Wilton Rancheria). The brochure will be distributed and the training will be conducted in coordination with qualified cultural resources specialists and Native American Representatives and Monitors from culturally affiliated Native American Tribes before any stages of project implementation and construction activities begin on the project site. The program will include relevant information regarding sensitive tribal cultural resources, including applicable regulations, protocols for avoidance, and consequences of violating state laws and regulations. The worker cultural resources awareness program will also describe appropriate avoidance and minimization measures for resources that have the potential to be located on the project site and will outline what to do and whom to contact if any potential archaeological resources or artifacts are encountered. The program will also underscore the requirement for confidentiality and culturally-appropriate treatment of any find of significance to Native Americans and behaviors, consistent with Native American Tribal values.

(Tribal Cultural Resources Mitigation Measure TCR-2) - Monitoring

32. To minimize the potential for destruction of or damage to existing or previously undiscovered burials, archaeological and tribal cultural resources and to identify any such resources at the earliest possible time during project-related earthmoving activities, Phillips 66 and its construction contractor(s) will implement the following measures:

- Paid Native American monitors from culturally affiliated Native American Tribes will be invited to monitor the vegetation grubbing, stripping, grading or other ground-disturbing activities in the project area to determine the presence or absence of any cultural resources. Native American representatives from cultural affiliated Native American Tribes act as a representative of their Tribal government and shall be consulted before any cultural studies or ground-disturbing activities begin.

- Native American representatives and Native American monitors have the authority to identify sites or objects of significance to Native Americans and to request that work be stopped, diverted or slowed if such sites or objects are identified within the direct impact area. Only a Native American representative can recommend appropriate treatment of such sites or objects.

- If buried cultural resources, such as chipped or ground stone, historic debris, building foundations, or bone, are discovered during ground-disturbing activities, work will stop in that area and within 100 feet of the find until an archaeologist who meets the Secretary of the Interior's qualification standards can assess the significance of the find and, if necessary, develop appropriate treatment measures in consultation with the California Department of Transportation, the State Historic Preservation Office, and other appropriate agencies. Appropriate treatment measures may include development of avoidance or protection methods, archaeological excavations to recover important information about the resource, research, or other actions determined during consultation.

- In accordance with the California Health and Safety Code, if human remains are uncovered during ground disturbing activities, the construction contractor or the County, or both, shall immediately halt potentially damaging excavation in the area of the burial and notify the County coroner and a qualified professional archaeologist to determine the nature of the remains. The coroner shall examine all discoveries of human remains within 48 hours of receiving notice of a discovery on private or state lands, in accordance with Section 7050(b) of the Health and Safety Code. If the coroner determines that the remains are those of a Native American, they shall contact the NAHC by phone within 24 hours of making that determination (Health and Safety Code Section 7050[c]). After the coroner's findings are presented, the County, the archaeologist, and the NAHC-designated MLD shall determine the ultimate treatment and disposition of the remains and take appropriate steps to ensure that additional human interments are not disturbed.

(Tribal Cultural Resources Mitigation Measure TCR-3) - Inadvertent Discoveries

33. Phillips 66 shall develop a standard operating procedure, or ensure any existing procedure, to include points of contact, timeline and schedule for the project so all possible damages can be avoided or alternatives and cumulative impacts properly accessed.

34. If potential tribal cultural resources, archaeological resources, other cultural resources, articulated, or disarticulated human remains are discovered by Native American Representatives or Monitors from interested Native American Tribes, qualified cultural resources specialists or other Project personnel during construction activities, work will cease in the immediate vicinity of the find (based on the apparent distribution of cultural resources), whether or not a Native American Monitor from an interested Native American Tribe is present. A qualified cultural resources specialist and Native American Representatives and Monitors from culturally affiliated Native American Tribes will assess the significance of the find and make recommendations for further evaluation and treatment as necessary. These recommendations will be documented in the project record. For any recommendations made by interested Native American Tribes which are not implemented, a justification for why the recommendation was not followed will be provided in the project record.

35. If adverse impacts to tribal cultural resources, unique archeology, or other cultural resources occurs, then consultation with Wilton Rancheria regarding mitigation contained in the Public Resources Code sections 21084.3(a) and (b) and CEQA Guidelines section 15370 should occur, in order to coordinate for compensation for the impact by replacing or providing substitute resources or environments.

36. If cultural resources are recovered on State lands, submerged or tidal lands, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the California State Lands Commission.

(Tribal Cultural Resources Mitigation Measure TCR-4) - Avoidance and Preservation

37. Avoidance and preservation in place is the preferred manner of mitigating impacts to tribal cultural resources and shall be accomplished by several means, including:

    - Planning construction to avoid tribal cultural resources, archaeological sites and/ or other resources; incorporating sites within parks, green-space or other open space; covering archaeological sites; deeding a site to a permanent conservation easement; or other preservation and protection methods agreeable to consulting parties and regulatory authorities with jurisdiction over the activity. Recommendations for avoidance of cultural resources will be reviewed by the CEQA lead agency representative, interested Native American Tribes and the appropriate agencies, in light of factors such as costs, logistics, feasibility, design, technology and social, cultural and environmental considerations, and the extent to which avoidance is consistent with project objectives. Avoidance and design alternatives may include realignment within the project area to avoid cultural resources, modification of the design to eliminate or reduce impacts to cultural resources or modification or realignment to avoid highly significant features within a cultural resource. Native American Representatives from interested Native American Tribes will be allowed to review and comment on these analyses and shall have the opportunity to meet with the CEQA lead agency representative and its representatives who have technical expertise to identify and recommend feasible avoidance and design alternatives, so that appropriate and feasible avoidance and design alternatives can be identified.

    - If the resource can be avoided, the construction contractor(s), with paid Native American monitors from culturally affiliated Native American Tribes present, will install protective fencing outside the site boundary, including a buffer area, before construction restarts. The construction contractor(s) will maintain the protective fencing throughout construction to avoid the site during all remaining phases of construction. The area will be demarcated as an "Environmentally Sensitive Area." Native American representatives from interested Native American Tribes and the CEQA lead agency representative will also consult to develop measures for long term management of the resource and routine operation and maintenance within culturally sensitive areas that retain resource integrity, including tribal cultural integrity, and including archaeological material, Traditional Cultural Properties and cultural landscapes, in accordance with state and federal guidance including National Register Bulletin 30 (Guidelines for Evaluating and Documenting Rural Historic Landscapes), Bulletin 36 (Guidelines for Evaluating and Registering Archaeological Properties), and Bulletin 38 (Guidelines for Evaluating and Documenting Traditional Cultural Properties); National Park Service Preservation Brief 36 (Protecting Cultural Landscapes: Planning, Treatment and Management of Historic Landscapes) and using the Advisory Council on Historic Preservation's Native American Traditional Cultural Landscapes Action Plan for further guidance. Use of temporary and permanent forms of protective fencing will be determined in consultation with Native American representatives from interested Native American Tribes.

CONDITIONS OF APPROVAL ADMINSTERED BY THE PUBLIC WORKS DEPARTMENT

Applicant shall comply with the requirements of Title 8, Title 9 and Title 10 of the Ordinance Code. Any exceptions must be stipulated in these Conditions of Approval. Conditions of Approval are based on the materials submitted to the Department of Conservation and Development on August 13, 2020.

COMPLY WITH THE FOLLOWING CONDITIONS OF APPROVAL PRIOR TO ISSUANCE OF A BUILDING PERMIT.

General Requirements

38. Improvement plans prepared by a registered civil engineer shall be submitted, if necessary, to the Public Works Department, Engineering Services Division, along with review and inspection fees, and secu¬rity for all improvements required by the Ordinance Code for the conditions of approval of this permit. Any necessary traffic signing and striping shall be included in the improvement plans for review by the Transportation Engineering Division of the Public Works Department.

Roadway Improvements (Frontage/Off-Site)

39. Any cracked and displaced curb, gutter, and sidewalk shall be removed and replaced along the project frontage of San Pablo Avenue. Concrete shall be saw-cut prior to removal. Existing lines and grade shall be maintained. New curb and gutter shall be doweled into existing improvements. (See Mitigation Measure TRA-1 above.)

Access to Adjoining Property

40. Encroachment Permit

    - Applicant shall obtain an encroachment permit from the Public Works Department, if necessary, for Traffic Control and signal optimization within the right-of-way of San Pablo Avenue and Cummings Skyway.
    - Applicant shall obtain an encroachment permit from Caltrans for Traffic Control within the State right-of-way.
    - Applicant shall obtain an encroachment permit from the City of Hercules for Traffic Control within the City right-of-way.

41. Site Access - Applicant shall only be permitted access at the locations shown on the approved site/development plan.

Construction

42. Prior to the start of construction-related activities, the applicant shall prepare a Traffic Control Plan (TCP), including a haul route, for the review and approval of the Public Works Department.

43. Applicant shall survey the pavement condition on San Pablo Avenue and Cummings Skyway prior to the commencement of any work on site, with Public Works Department approval. The survey shall include a photo/video of the roadways. Applicant shall complete any remedial work prior to initiation of use; OR, provide a bonded agreement assuring completion of the remedial work.

44. Applicant shall provide a pavement analysis for those roads along the proposed haul route or any alternate route(s) that are proposed to be utilized by the hauling operation. This study shall analyze the existing pavement conditions, and determine what impact the hauling operation

will have over the life of the project. The study shall provide recommendations to mitigate identified impacts.

ADVISORY NOTES

ADVISORY NOTES ARE NOT CONDITIONS OF APPROVAL; THEY ARE PROVIDED TO ALERT THE APPLICANT TO ADDITIONAL ORDINANCES, STATUTES, AND LEGAL REQUIREMENTS OF THE COUNTY AND OTHER PUBLIC AGENCIES THAT MAY BE APPLICABLE TO THIS PROJECT.

A. NOTICE OF OPPORTUNITY TO PROTEST FEES, ASSESSMENTS, DEDICATIONS, RESERVATIONS OR OTHER EXACTIONS PERTAINING TO THE APPROVAL OF THIS PERMIT.

Pursuant to California Government Code Section 66000, et seq., the applicant has the opportunity to protest fees, dedications, reservations or exactions required as part of this project approval. To be valid, a protest must be in writing pursuant to Government Code Section 66020 and must be delivered to the Community Development Division within a 90-day period that begins on the date that this project is approved. If the 90th day falls on a day that the Community Development Division is closed, then the protest must be submitted by the end of the next business day.

B. Additional requirements may be imposed by the following agencies and departments; the applicant is strongly encouraged to review these agencies' requirements prior to continuing with the project:
- Contra Costa County, Building Inspection Division
- Contra Costa County, Public Works Department
- Rodeo-Hercules Fire Protection District
- Contra Costa County, Health Services, Hazmat
- Bay Area Air Quality Management District
- Regional Water Quality Control Board
- California Department of Fish and Wildlife
- California Department of Transportation
- East Bay Municipal Utility District
- Pacific Gas and Electric Company
- San Francisco Bay Conservation and Development Commission
- California State Lands Commission

C. The applicant will need to comply with the requirements of the Bridge/Thoroughfare Fee Ordinance for the Hercules/Rodeo/Crockett and West Contra Costa Transpiration Advisory Committee Areas of Benefit as adopted by the Board of Supervisors. The fee shall be paid prior to initiation of use.

APPENDIX A

GUARANTEE

Shall be on guarantor's letterhead stationery. It shall also contain original signature of Guarantor

[TITLE]
[AGENCY]
[ADDRESS]

Guarantee made this _______Date_________ by __________Name of Guaranteeing Entity_______________, a business entity organized under the laws of ___________Insert Name of State_______________, herein referred to as Guarantor, to the [AGENCY (Contra Costa County)] obligee on behalf of ______Applicant of _____________________________________Business Address____.

Recitals

1. Guarantor meets or exceeds the financial means test criteria for guarantors, which means that Guarantor shall have:
    a. A current rating for its most recent bond issuance of AAA, AA, A, or BBB issued by Standard and Poor's or Aaa, Aa, A or Baa as issued by Moody's; and
    b. Tangible net worth each at least six times the amount of the current cost estimate to be demonstrated by the test; and
    c. Tangible net worth of at least $15 million; and
    d. Assets located in the United States amounting to at least 90 percent of its total assets or at least six times the amount of the current cost estimate to be demonstrated by the test.

2. Guarantor is a parent corporation of the ________________Applicant______________ ; ☐ is a firm whose parent corporation, _______________Corporate Parent__________________________ , is also the parent corporation of Operator____________________________; or ☐ engages in a substantial business relationship with ____________________Applicant and is issuing this guarantee as an act incident to that business relationship.

3. ________________Applicant______________________ has developed a Demolition and Site Clean-up Work Plan as required by the [SPECIFY LAND USE PERMIT].

4. [Insert appropriate phrase: "On behalf of our subsidiary" (if guarantor is a parent corporation of the Applicant); "On behalf of our affiliate" (if guarantor is a firm whose parent corporation is also the parent corporation of the Applicant); or "Incident to our business relationship with" (if guarantor is providing guarantee as an incident to a substantial business relationship with the Applicant)] ________________Applicant_____________ . Guarantor guarantees to Contra Costa County that in the event that ________________Applicant_____________ fails to perform activities identified in the Demolition and Site Clean-up Work Plan whenever required to do so, Guarantor shall do so.

5. Guarantor agrees that if at any time during or at the end of any fiscal year before termination of this guarantee the Guarantor fails to meet the financial means test criteria, Guarantor shall send within 90 days, by either registered or certified mail, notice to Contra Costa County, and the ___________Applicant____________, of such failure and that he or she intends to provide alternate financial assurance, including without limitation surety bond, letter of credit, insurance or trust fund, as applicable, in the name of ____________Applicant_____________ if the ____________Applicant____________fails to obtain such assurance. Within 120 days after the end of such fiscal year or other occurrence, Guarantor shall establish such alternate financial assurance in the name of ____________Applicant____________ in the amount of the applicable current cost estimate, unless ____________Applicant has done so.

6. Guarantor agrees to notify Contra Costa County, and the ___________Applicant____________, by either registered or certified mail of a voluntary or involuntary proceeding under the Bankruptcy Code, 11 U.S.C. Sections 101-1330, naming Guarantor as debtor within ten days after commencement of the proceeding.

7. Guarantor agrees to remain bound under this guarantee notwithstanding amendment or modification of the Demolition and Site Clean-up Work Plan.

8. Guarantor agrees to remain bound under this guarantee for so long as Applicant must comply with the applicable financial assurance requirements in the Land Use Permit, except that Guarantor may cancel this guarantee by sending notice by registered or certified mail to Contra Costa County, and the Applicant. Such cancellation shall become effective no earlier than 120 days after receipt of such notice by Contra Costa County, and the Applicant, as evidenced by the return receipts.

11. Guarantor agrees that if Applicant fails to provide alternate financial assurance, including without limitation surety bond, letter of credit, insurance or trust fund, as applicable, within 90 days after a notice of cancellation by Guarantor is received from Guarantor by Contra Costa County, and the Applicant, Guarantor shall provide such alternate financial assurance in the name of Applicant in the amount of the applicable current cost estimate.

12. Guarantor expressly waives notice of acceptance of this guarantee by Contra Costa County, or the Applicant. Guarantor also expressly waives notice of amendments or modifications of the Demolition and Site Clean-up Work Plan.

The parties below certify that this document is being executed in accordance with the requirements of the Contra Costa County land use permit.

Effective date: ____

____
Name of Guarantor

____
Authorized Signature of Guarantor

➢

____
Typed or Printed Name of Person Signing

____
Title and Phone Number of Person Signing

➢

____
Signature of Witness or Notary and Seal

Privacy Statement

The Information Practices Act (California Civil Code Section 1798.17) and the Federal Privacy Act (5 U.S.C. 552a(e)(3)) require that this notice be provided when collecting personal information from individuals.

AGENCY REQUESTING INFORMATION: California Department of Resources Recycling and Recovery (CalRecycle).

UNIT RESPONSIBLE FOR MAINTENANCE OF FORM: Financial Assurances Section, California Department of Resources Recycling and Recovery (CalRecycle), 1001 I Street, P.O. Box 4025, Sacramento, California 95812-4025. Contact the Manager, Financial Assurances Section, at (916) 341-6000.

AUTHORITY: Public Resources Code section 43600 et seq.

PURPOSE: The information provided will be used to verify adequate financial assurance of solid waste disposal facilities listed.

REQUIREMENT: Completion of this form is mandatory. The consequence of not completing this form is denial or revocation of a permit to operate a solid waste disposal facility.

OTHER INFORMATION: After review of this document, you may be requested to provide additional information regarding the acceptability of this mechanism.

ACCESS: Information provided in this form may be provided to the U.S. Environmental Protection Agency, State Attorney General, Air Resources Board, California Department of Toxic Substances Control, Energy Resources Conservation and Development Commission, Water Resources Control Board, and California Regional Water Quality Control Boards. For more information or *access to your records, contact the California Department of Resources Recycling and Recovery (CalRecycle) , 1001 I Street, P.O. Box 4025, Sacramento, California 95812-4025, (916) 341-6000.*

LINK TO PHILLIPS 66 RODEO RENEWED PROJECT DRAFT AND FINAL ENVIRONMENTAL IMPACT REPORTS (State Clearinghouse #2020120330)

https://www.contracosta.ca.gov/7945/Phillips-66-Rodeo-Renewed-Project

COMMUNITY BENEFITS AGREEMENT

between

CONTRA COSTA COUNTY and PHILLIPS 66 COMPANY

County File CDLP#20-02040

This Community Benefits Agreement ("Agreement") is entered into as of _____________, 2022 ("Effective Date") by and between Contra Costa County ("County"), a political subdivision of the State of California, and Phillips 66 Company ("Phillips 66"), a Delaware corporation.

RECITALS

A. On_________, 2022, the County Planning Commission certified the environmental impact report (the "EIR") and issued to Philips 66 a land use permit (the "LUP") for Phillips 66's Rodeo Renewed Project (the "Project"), located at Phillips 66's existing Rodeo Refinery (the "Refinery") in the unincorporated community of Rodeo, Contra Costa County (County File No. CDLP20-02040). The Project will repurpose the Refinery for the production of fuels from renewable sources rather than from crude oil.

B. In addition to obtaining the LUP and other discretionary state and local approvals to construct and operate the Project, including a final Authority to Construct from the Bay Area Air Quality Management District (the "BAAQMD Air Permit"), Phillips 66 intends to obtain one or more County building permits to construct improvements at the Refinery necessary for the Project.

C. The proposed Project is a unique land use with unique impacts on the community. The LUP contains Condition of Approval No. __, which provides that Contra Costa County and Phillips 66 will enter into a Community Benefits Agreement providing for certain payments to Contra Costa County upon certain conditions being satisfied relating to the Project.

AGREEMENT

NOW THEREFORE, Contra Costa County and Phillips 66 agree as follows:

1. Purpose. The purpose of this Agreement is to memorialize Philips 66's commitment to making an annual community benefits payment to the County and participating in a local workforce training and development program during the term of this Agreement.

2. Term. The term ("Term") of this Agreement begins on the Effective Date, and it expires upon the earliest of any of the following to occur: (a) the payment of the final community benefit payment provided for in Section 3; (b) the revocation of the LUP; or (c) the effective date of any court decision that invalidates or sets aside the Project, the LUP, the EIR, or the BAAQMD Air Permit.

3. Community Benefits Payments.

a. Phillips 66 shall pay $1,000,000 to County (the "First Payment") upon the County's final approval of the LUP, or upon the Bay Area Air Quality Management District's final approval of the BAAQMD Air Permit, whichever occurs later. "Final Approval" means that the LUP and the BAAQMD Air Permit have both been issued, the respective statutes of limitations for challenging the issuance of each permit has run, and any pending legal challenges or appeals have been finally resolved. The First Payments shall be made to the County within 30 days following the Final Approval described above.

b. Upon the County's issuance of the first building permit authorizing construction of improvements covered by the LUP, Phillips 66 shall pay $1,000,000 to the County (the "Second Payment"). The Second Payment shall be made no later than December 31 of the year in which the first building permit is issued.

c. Beginning in the year when Phillips 66 first produces renewable fuels from equipment covered by the LUP, Phillips 66 shall pay 12 annual payments of $615,000 to the County (each a "Subsequent Payment"), and shall pay to the County a final payment of $620,000 in year 13 (the "Final Payment") . Each of these 13 payments shall be made to the County no later than December 31 of each year.

d. Beginning on January 1, 2023, and on each January 1 thereafter, the payment amounts provided for in this Section 3, including the First Payment, the Second Payment, each Subsequent Payment, and the Final Payment, shall increase based on any increase in the Consumer Price Index for the San Francisco-Oakland-Hayward Combined Statistical Area (U.S. Bureau of Labor Statistics) for the 12-month period ending on the October 31 immediately preceding the January 1 when the increase takes effect.

4. Use of Payments. The County shall, in its sole discretion, allocate funds received pursuant to this Agreement to projects and programs that benefit the communities near the Refinery by improving the health, well-being, and quality of life of residents, and that support building and sustaining a strong and resilient local economy and workforce, including the development and implementation of workforce development and training programs to prepare residents for new renewable and clean energy career pathways and jobs.

5. Other Community Benefits. In addition to the payments made by Phillips 66 under Section 3, and in partnership with the County, Phillips 66 commits to actively participate with other appropriate stakeholders in planning and designing a Workforce Training Program (the "Program") for local community members related to renewable and clean energy employment opportunities. Notwithstanding Phillip 66's active participation, the County will facilitate and lead the process of Program development. This Program will focus on the development of programs and curricula, and may build on existing efforts, including but not limited to job training programs provided by employers and community-based organizations, community college programs, career readiness programs at local high schools, apprenticeship programs sponsored by labor organizations,

programs of the Workforce Development Board, work experience and placement services, and other workforce development initiatives within Contra Costa County. Phillips 66 commits to continue its ongoing investments in training and education to support the Program and its outcomes.

6. Notices. All payments, notices, demands, and other communications made under this Agreement shall be in writing and personally delivered, sent by overnight carrier with delivery charges prepaid for next business day delivery, or sent by First Class U.S. Mail with postage prepaid, and addressed as follows:

   To County: Director of Conservation and Development
   30 Muir Road
   Martinez, CA 94553

   To Phillips 66: ___________________________
   ____
   ____

   A payment, notice, demand, or other communication shall be deemed given on the same day it is personally delivered, on the next business day following deposit with and overnight carrier, or on the fifth day after deposit in the U.S. Mail. A party may change its address for delivery of notices under this Agreement by providing written notice of the change in accordance with this section.

7. Assignment. Phillip 66's obligations under this Agreement shall be binding upon Philips 66's successors and assigns. Phillips 66 shall not assign this Agreement, or any of its obligations under this Agreement, to any other person or entity without the advance written approval of the County, which shall be within its sole discretion to provide. If Phillips 66 sells, conveys, or otherwise transfers ownership of the Refinery to a third-party, Phillips 66 shall require that third-party to accept an assignment of this Agreement.

8. No Third-Party Beneficiaries. Nothing in this Agreement confers and rights or obligations on any person or entity that is not a party to this Agreement.

9. Counterparts. The Agreement may be executed in counterparts.

10. Governing Law. This Agreement shall be governed by the laws of the State of California.

The County and Phillips 66 have executed this agreement as specified below.

<u>CONTRA COSTA COUNTY</u>

____

Name: __________________________

Title: ___________________________

Date Signed: _____________________

<u>PHILLIPS 66 COMPANY</u>

____

Name: __________________________

Title: ___________________________

Date Signed: _____________________

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]

[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.

TABLE OF CONTENTS

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

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

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

I. STATEMENTS OF INTEREST

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. The Project Description Failed to Disclose All Project Components

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

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

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

[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

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[19] *Id.*
[20] In addition to process-specific operating temperatures, pressures, and engineered process controls such as quench and depressurization systems, examples include process unit-specific input, internal recycle rates, hydrogen consumption rates, and even how those operating conditions interact across refining processes to affect overall hydrogen demand when processing feedstocks of various qualities.
[21] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model.
[22] *Id.*

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

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

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

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

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

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

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

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

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[23] Karras, 2021a.
[24] Sun et al. 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Reforming Facilities. *Environ. Sci. Technol.* 53: 71.3–7113. DOI: 10.1021/acs.est.8b06197
[25] Karras, 2021a,
[26] *Id.*
[27] BAAQMD Causal Reports for Significant Flaring. BAAQMD Regulations, §12-12-406 of Regulation 12, Rule 12; Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd/gov/rules-and-compliance/current-rules
[28] *Id.*

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

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

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

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

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

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

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

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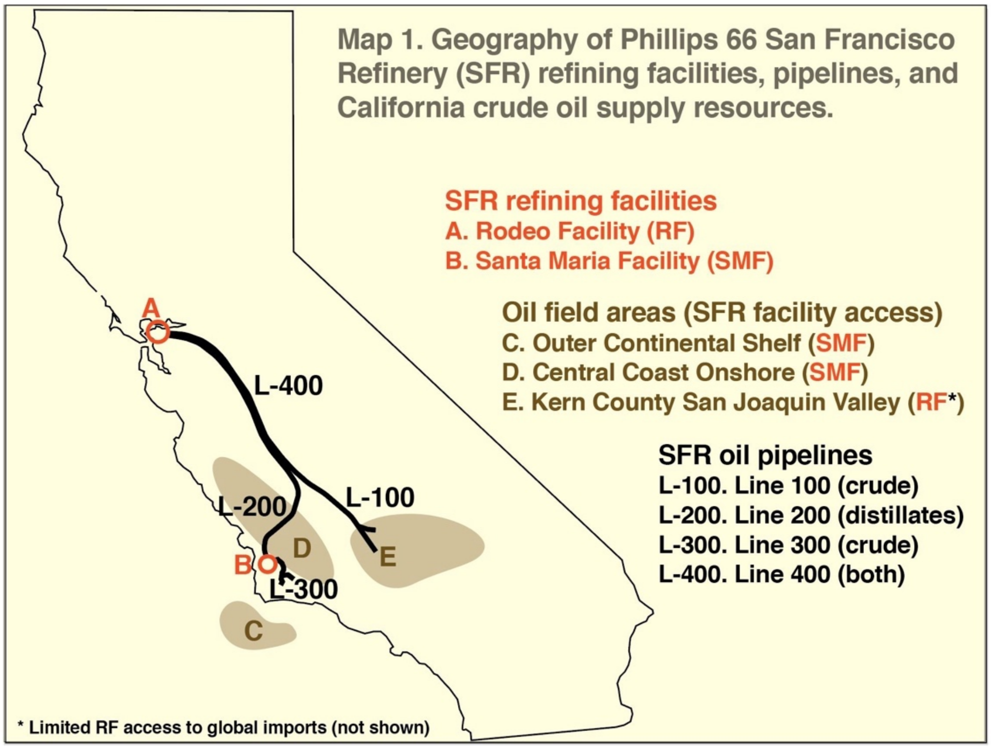
[41] The increase would be from the current marine terminal input limit of 51,182 barrels per day (b/d) limit now to 125,000 b/d.
[42] Application at 12.
[43] *Id.* at 11-12 (listing Project components).
[44] Map 1 is only approximately to scale, consistent with facility and pipeline maps in the DEIR, and based also upon state and federal oilfield location and accessibility data, as documented in Karras, 2021c.
[45] SLOC, 2014. *Phillips 66 Company Rail Spur Extension and Crude Unloading Project Revised Public Draft Environmental Impact Report;* prepared for San Luis Obispo County (SLOC) by Marine Research Specialists (MRS). October 2014. SCH# 2013071028. Excerpt including title page and project description.
[46] *Crude Oil Sources for California Refineries;* California Energy Commission: Sacramento, CA. (CEC, 2021a).



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

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

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

and Line 400 to the Refinery, where the Kern crude and partially refined oil output from the Santa Maria refinery both flow north through Line 400 to the Refinery.[52] The DEIR, however, erroneously describes Line 100 as directly supplying the Santa Maria refinery: "Two other pipelines—Line 100 and Line 300—*connect the Santa Maria Site* to crude oil collection facilities elsewhere in California ... [including] Kern County ... ." DEIR at 3-21 (emphasis added). This clear error in the DEIR obscures the fact that the Santa Maria refinery lacks access to San Joaquin oilfields—the largest remaining regional crude resource in California.[53] [54]

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

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

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[52] Karras, 2021c. Careful review of DEIR Figure 3-5 confirms this accurate description of pipeline flows, once the reader knows that crude <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. <u>Available Crude Supply Data Demonstrate Declining Feedstock Availability at the Santa Maria Facility</u>

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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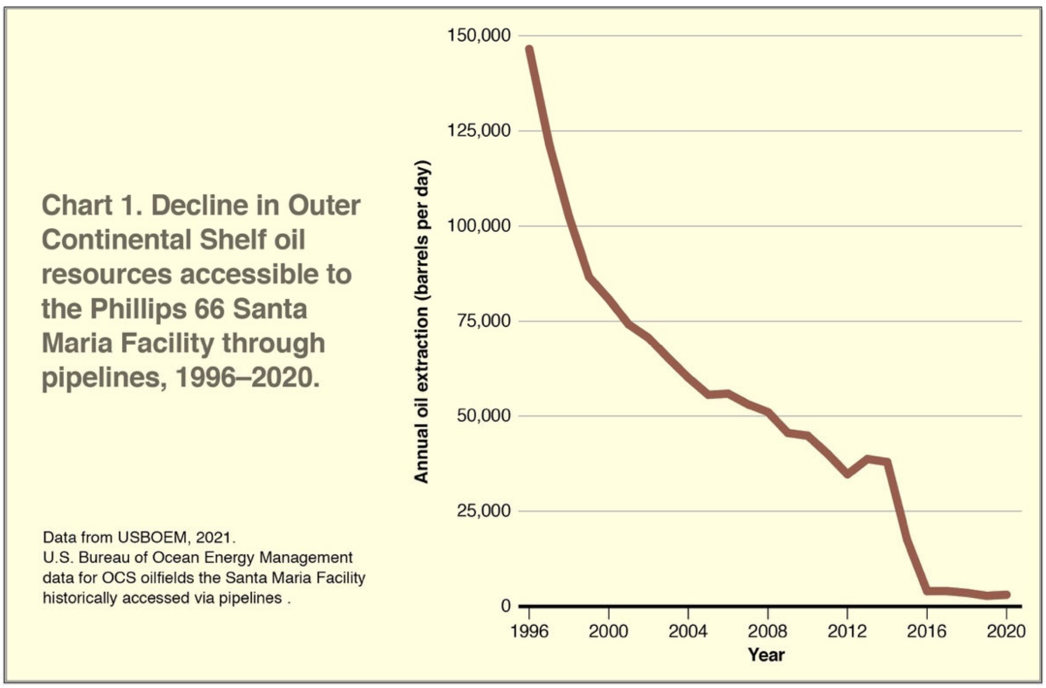
[62] SBC, 2021. *ExxonMobil Interim Trucking for SYU Phased Restart Project Status, Description, Timeline;* Santa Barbara County Department of Planning & Development. Website page accessed 18 November 2021.

[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.



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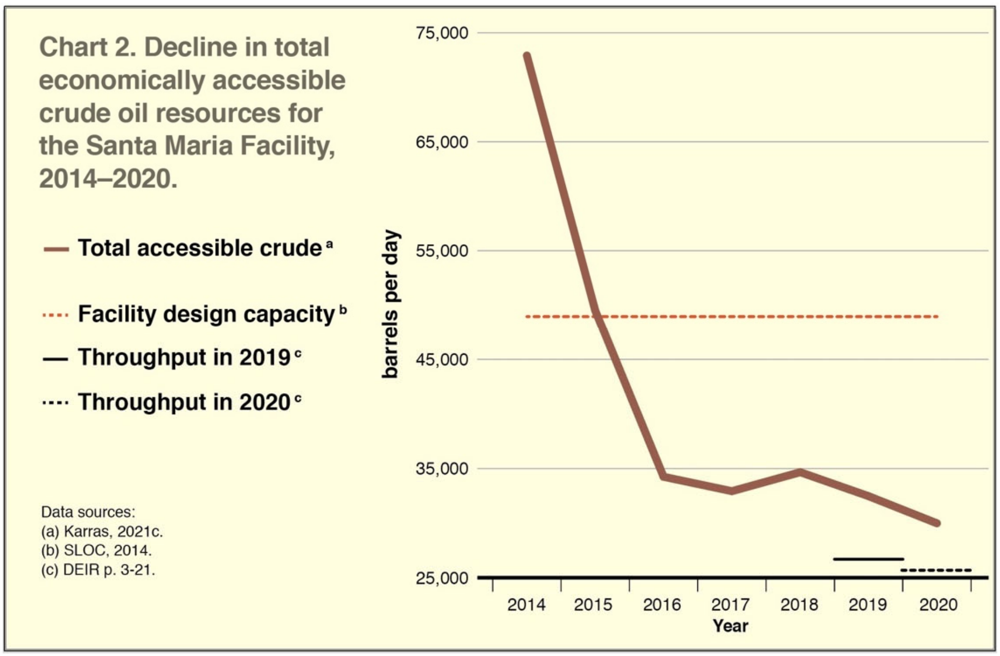
[64] SLOC, 2014.
[65] USBOEM, 2021a. U.S. Bureau of Ocean Energy Management. *Pacific Production;* data tables for the Pacific OCS Region, 1996–2021. https://www.data.boem.gov/Main/PacificProduction.aspx#ascii
[66] USBOEM, 2021b. U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement/Bureau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

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

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

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

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

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

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

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

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

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

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

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

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

[90] *Id.*

[91] *Id.*

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

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

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

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

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

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[92] Portner, H.O. et al., Scientific outcome of the IPBES-IPCC co-sponsored workshop on biodiversity and climate change, IPBES Secretariat, June 2021, 18-19, 28-29, 53-58. https://www.ipbes.net/events/launch-ipbes-ipcc-co-sponsored-workshop-report-biodiversity-and-climate-change (accessed Dec 8, 2021).
[93] Although as discussed in Section II, the DEIR never specifically mentions HEFA, the description generally references that technology, *i.e.,* briefly noting that the process feeds lipids, and more specifically, lipids from triacylglycerols (TAGs), and fatty acids cleaved from those TAGs, from biomass into the refinery.
[94] While fish oils are commercially available, they are extremely limited in availability. Food and Agriculture Organization of the United Nations (FAO), *The State of World Fisheries and Aquaculture: Sustainability in action*, 2020. http://www.fao.org/documents/card/en/c/ca9229en (accessed Dec 12, 2021); *see also* Yusuff, A., Adeniyi, O., Olutoye M., and Akpan, U. *Waste Frying Oil as a Feedstock for Biodiesel Production*, IntechOpen, 2018. http://dx.doi.org/10.5772/intechopen.79433 (accessed Dec 8, 2021).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[106] *Id.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[115] *Id*. at 79.
[116] Searle, S. *If we use livestock feed for biofuels, what will the cows eat?* The International Council on Clean Transportation, Jan. 2019. https://theicct.org/blog/staff/if-we-use-livestock-feed-biofuels-what-will-cows-eat (accessed Dec 8, 2021).
[117] *See* Final Rulemaking for Grain Sorghum Oil Pathways. 81 Fed. Reg. 37740-37742 (August 2, 2018), https://www.govinfo.gov/content/pkg/FR-2018-08-02/pdf/2018-16246.pdf (accessed Dec 8, 2021); *see also* EPA sets a first in accurately accounting for GHG emissions from waste biofuel feedstocks, International Council on Clean Transportation Blog (Sept. 2018), https://theicct.org/blog/staff/epa-account-ghg-emissions-from-waste (accessed Dec 8, 2021).
[118] Searle 2019.
[119] Gerber, P.J. et al., *Tackling climate change through livestock—A global assessment of emissions and mitigation opportunities*, Food and Agriculture Organization of the United Nations 2013, 8. https://www.fao.org/3/i3437e/i3437e.pdf (accessed Dec 8, 2021).
[120] Pavlenko, N. and Searle, S. *A comparison of methodologies for estimating displacement emissions from waste, residue, and by-product biofuel feedstocks*, Working Paper 2020-22, International Council on Clean Transportation, Oct 2020, 6. https://theicct.org/sites/default/files/publications/Biofuels-displacement-emissions-oct2020.pdf (accessed Dec 8, 2021).
[121] Baldino, Searle, and Zhou, 2020-25, pp. 6.
[122] Pavlenko and Searle 2020-22, pp. 26.

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

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

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

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[123] *See* Karras, G. Biofuels: Burning Food?, Community Energy resource, 2021. https://f61992b4-44f8-48d5-9b9d-aed50019f19b.filesusr.com/ugd/bd8505_a077b74c902c4c4888c81dbd9e8fa933.pdf (accessed Dec 8, 2021).
[124] DEIR xxii.
[125] Uses EIA data from the Monthly Biodiesel Production Report, Table 3. This 113,000 b/d estimate is based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil).
[126] DEIR xxii . The Project percentage boost over existing biofuel feedstock consumption is from 80,000 b/d, divided by that 113,000 b/d from existing biodiesel production.
[127] This 372,000 b/d estimate is from two sources. First, data were taken from the U.S. Department of Agriculture (USDA) "Oil Crops Data: Yearbook Tables" data. U.S. Department of Agriculture (USDA), Oil Crops Yearbook Tables 5, 26, and 33, Mar. 26, 2021, https://www.ers.usda.gov/data-products/oil-crops-yearbook/ (accessed Dec. 14, 2021). Specifically, from Oct. 2016 through Sep. 2020 average total U.S. yields were: 65.1 million pounds per day (MM lb/d), or 202,672 b/d at a specific gravity (SG) of 0.916 for soybean oil (*see* i below), 4.62 MM lb/d or 14,425 b/d at 0.915 SG for canola oil (ii), and 15.8 MM lb/d or 49,201 b/d at 0.923 SG for corn oil (iii).. *See* USDA Oil Crops Yearbook (OCY) data tables (i) OCY Table 5, (ii) OCY Table 26, (iii) OCY Table 33, (iv) OCY Table 20), (v) OCY Table 32. Second, we estimated total U.S. production of other animal fats and waste oils from the U.S. Department of Agriculture (USDA) "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks" Annual Summaries. National Agricultural Statistics Service, "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks Annual Summary", 2017 through 2020, https://usda.library.cornell.edu/concern/publications/mp48sc77c. (accessed Dec. 14, 2021). Specifically, from 2017 to 2020, average total U.S. yields were: 16.2 MM lb/d or 51,386 b/d for edible, inedible, and technical tallow production, 6.65 MM lb/d or 22,573 b/d for poultry fat production, 4.52 MM lb/d or 13,420 b/d for lard and choice white grease production, and 5.83 MM lb/d or 18,272 b/d for yellow grease production.
[128] This figure represents Project feedstock demand of 80,000 b/d over the estimated 372,000 b/d total lipid production in the U.S. calculated in the previous footnote.

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

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

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

[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.

[144] Malins 2020a, pp. 57.

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

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

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

[148] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "The Deir Does Not Provide A Complete or Accurate Analysis of Process Hazards and Does Not Identify, Evaluate, or Mitigate Significant Potential Project Hazard Impacts."

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[155] Chan, 2020 as cited above at 3.
[156] Flaring causal analyses, various dates. Reports required by Bay Area Air Quality Management District Regulation 12, Rule 12, including reports posted at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports and reports for incidents predating those posted at that link.
[157] Flaring causal analyses as cited above. Hydro-conversion includes hydrotreating and hydrocracking.
[158] *Id.*
[159] Flaring causal analyses as cited above. *See* reports for incidents starting 13 May 2010, 17 February 2011 and 17 April 2015.

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire;[160]
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage;[161]
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor;[162]
- A 2015 hydrogen conduit explosion throws workers against a refinery structure;[163]
- Fifteen workers die, and 180 others are injured, in a series of 2005 explosions when hydrocarbons flood a distillation tower during an isomerization unit restart;[164]
- A vapor release from a valve bonnet failure in a high-pressure hydrocracker section ignites in a major 1999 explosion and fire at the Chevron Richmond refinery;[165]
- A worker dies, 46 others are injured, and the surrounding community is forced to shelter in place when a release of hydrogen and hydrocarbons under high temperature and pressure ignites in a 1997 hydrocracker explosion and fire at the Tosco (now Marathon) Martinez refinery;[166]
- A Los Angeles refinery hydrogen processing unit pipe rupture releases hydrogen and hydrocarbons that ignite in a 1992 explosion and fires that burn for three days;[167]
- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on nearby Richmond refinery equipment;[168]
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.[169]

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

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

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

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

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

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

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

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

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

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

[174] See CCR § 5189.1 (c).

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

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

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

- *Feedstock processing hazard condition.* The County could adopt a Project condition to forgo or minimize the use of particularly high process hydrogen demand feedstocks. Since increased process hydrogen demand would be a causal factor for the significant process hazard impacts and some HEFA feedstocks increase process hydrogen demand significantly more than other others, avoiding feedstocks with that more hazardous processing characteristic would lessen or avoid the hazard impact.
- *Product slate processing hazard condition.* The County could adopt a Project condition to forgo or minimize particularly high-process hydrogen demand product slates. Minimizing or avoiding HEFA refining to boost jet fuel yield, which significantly increases hydrogen demand, would thereby lessen or avoid further intensified hydrogen reaction hazard impacts.
- *Hydrogen input processing hazard condition.* The County could adopt a Project condition to limit hydrogen input per barrel, which could lessen or avoid the process hazard impacts from particularly high-process hydrogen demand feedstocks, product slates, or both.
- *Hydrogen backup storage processing hazard condition.* The County could adopt a Project condition to store hydrogen onsite for emergency backup use. This would lessen or avoid hydro-conversion plant incident impacts caused by the sudden loss of hydrogen inputs when hydrogen plants malfunction, a significant factor in escalating incidents.

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

[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. <u>Processing Biofuel Feedstock Instead of Crude Oil Can Increase Carbon Emission Intensity of the Refining Process</u>

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. <u>*See*</u> also Karras, 2021a.
b. Data from Sun et al. for median California merchant steam methane reforming hydrogen plant performance. Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 Note that these steam methane reforming plant data are shown for context. Steam reforming of HEFA byproduct propane can be expected to increase direct emissions from the steam reforming and shift reactions. Karras, 2021a. Mass emissions based on 80,000 b/d project capacity. Fish oil values shown are based on Menhaden.

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

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

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

2. GHG Emissions Impacts Vary With Different Potential Feedstocks

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

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

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

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

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

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

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

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

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[181] *See* Chevron Refinery Modernization Project EIR. SCH # 2001062042. 2014. City of Richmond, CA. *See* esp. pp. 4.8-11, 4.8-12, 4.8-18, 4.8-19, 4.8-24, 4.8-27, 4.8-28, 4.8-38, 4.8-70 (10,000 metric tons/yr significance threshold).
[182] Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 .
[183] Guha et al., 2020. *Environ. Sci. Technol.* 54: 9254–9264 and Supporting Information. https://dx.doi.org/10.1021/acs.est.0c01212

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

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

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

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

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

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

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[184] Seber et al., 2014. *Biomass and Bioenergy* 67: 108–118. http://dx.doi.org/10.1016/j.biombioe.2014.04.024. *See* also Karatzos et al., 2014. Report T39-T1, IEA Bioenergy Task 39. IEA ISBN: 978-1-910154-07-6. (*See* esp. p. 57; extra processing and hydrogen required for jet fuel over diesel.) https://task39.sites.olt.ubc.ca/files/2014/01/Task-39-Drop-in-Biofuels-Report-FINAL-2-Oct-2014-ecopy.pdf *See also* Karras, 2021b.
[185] Legislative Information, AB-32, California Global Warming Solutions Act of 2006 (Accessed November 29, 2021), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html
[186] Legislative Information, SB-32 California Global Warming Solutions Act of 2006: Emissions Limit, (Accessed November 29, 2021), from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32
[187] Executive Order S-3-05. Executive Department, State of California, Arnold Schwarzenegger, Governor, State of California; https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/5129-5130.pdf.
[188] Executive Order B-55-18. Executive Department, State of California, Edmund Brown, Governor, State of California; https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.
[189] Executive Order N-79-20. Executive Department, State of California, Gavin Newsom, Governor, State of California; https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

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

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

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

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

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

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

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

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

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

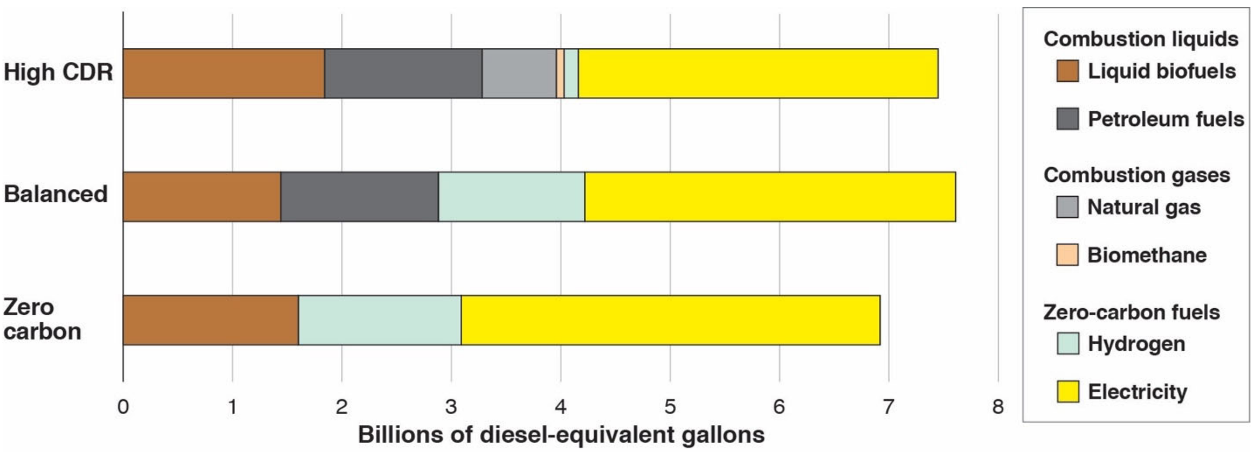

Chart 3: California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.
Adapted from Figure 8 in Mahone et al. (2020).[200] Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion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

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[195] Mahone et al 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2021; Reed et al., 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California;* Final Project Report CEC-600-2020-002. Prepared for the California Energy Commission by U.C. Irvine Advanced Power and Energy Program. Clean Transportation Program, California Energy Commission: Sacramento, CA. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292; Williams et al., 2012. The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. *Science* 53–59. https://doi.org/DOI: 10.1126/science.1208365; Williams et al., 2015. Pathways to Deep Decarbonization in the United States; The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute of Sustainable Development and International Relations. Revision with technical supp. Energy and Environmental Economics, Inc., in collaboration with Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory. https://usddpp.org/downloads/2014-technical-report.pdf; Williams et al., 2021. Carbon-Neutral Pathways for the United States. *AGU Advances* 2, e2020AV000284. https://doi.org/10.1029/2020AV000284.
[196] Mahone et al. 2020a.
[197] Mahone et al. 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2020; Reed et al. 2020.
[198] Mahone et al. 2018; Mahone et al. 2020a; Reed et al. 2020.
[199] Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf
[200] Mahone et al., 2020.

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

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

[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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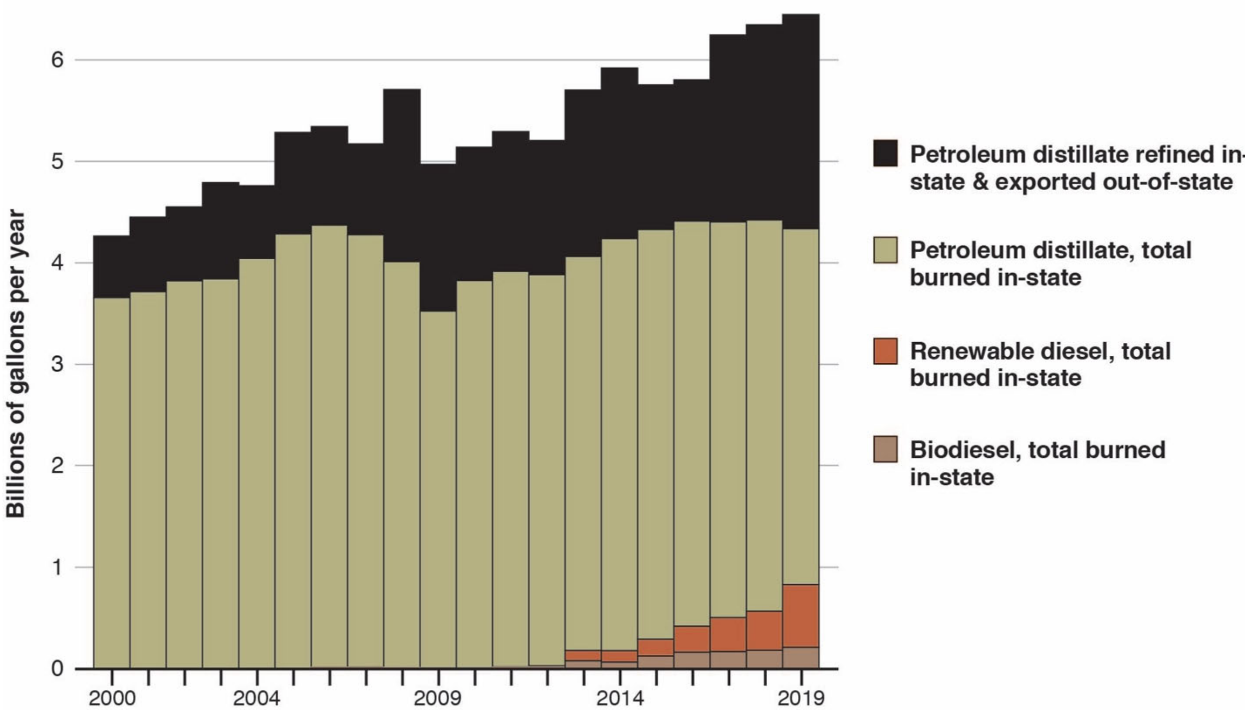
[211] "Project operations would decrease emissions of GHGs that could contribute to global climate change" (DEIR p. 2-5) including "indirect emissions" (DEIR p. 4.8-258) and "emissions from transportation fuels" (DEIR p. 4.8-266).
[212] CCR §§ 38505 (j), 38562 (b) (8).
[213] CEC, Fuel Watch data.
[214] 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	Pre-COVID range (2010–2019)			Comparison of 2021 data with
	in 2021	Minimum	Median	Maximum	the same month in 2010–2019
Gasoline (MM bbl.)					
Jan	38.59	42.31	45.29	49.73	Below pre-COVID range
Feb	38.54	40.94	42.75	47.01	Below pre-COVID range
Mar	45.14	45.23	48.97	52.53	Approaches pre-COVID range
Apr	44.97	44.99	47.25	50.20	Approaches pre-COVID range
May	48.78	46.79	49.00	52.18	Within pre-COVID range
Jun	48.70	45.61	48.14	51.15	Exceeds pre-COVID median
Jul	50.12	47.33	49.09	52.39	Exceeds pre-COVID median
Jet fuel (MM bbl.)					
Jan	9.97	11.57	13.03	19.07	Below pre-COVID range
Feb	10.35	10.90	11.70	18.33	Below pre-COVID range
Mar	11.08	11.82	13.68	16.68	Below pre-COVID median
Apr	11.71	10.83	13.78	16.57	Within pre-COVID range
May	12.12	12.80	13.92	16.90	Approaches pre-COVID range
Jun	14.47	13.03	14.99	17.64	Within pre-COVID range
Jul	15.31	13.62	15.46	18.41	Within pre-COVID range
Diesel (MM bbl.)					
Jan	15.14	12.78	14.41	15.12	Exceeds pre-COVID range
Feb	15.01	12.49	13.51	15.29	Exceeds pre-COVID median
Mar	17.08	14.12	15.25	16.33	Exceeds pre-COVID range
Apr	15.76	14.14	14.93	16.12	Exceeds pre-COVID median
May	16.94	15.11	15.91	17.27	Exceeds pre-COVID median
Jun	14.65	14.53	16.03	16.84	Within pre-COVID range
Jul	16.94	15.44	16.40	17.78	Exceeds pre-COVID median

Data 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. <u>*See*</u> USEIA, 2021a. *Refinery Capacity Data by Individual Refinery as of January 1, 2021;* U.S. Energy Information Administration: Washington, D.C. Accessed 3 Nov 2021. https://www.eia.gov/petroleum/data.php

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

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

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

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

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

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

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

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

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

[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.

[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. Haldor Topsoe HydroFlex technology results in successful test run at Marathon Petroleum Corp facility producing 100% renewable diesel, Haldor Topsoe, Aug 5. 2021, https://blog.topsoe.com/marathon-petroleum-corporation-confirms-successful-test-run-for-us-refinery-producing-100-renewable-diesel-based-on-topsoes-hydroflex-technology (accessed Dec 14, 2021). **b.** Viking Energy Group, Inc. Viking Energy Signs Agreement to Acquire Renewable Diesel Facility, Globe Newswire, Dec. 1, 2021, ttps://www.globenewswire.com/news-release/2021/12/01/2344429/0/en/Viking-Energy-Signs-Agreement-to-Acquire-Renewable-Diesel-Facility.html (accessed Dec 14, 2021). **c.** Cox, J. Refinery on Rosedale makes final changes for switch to cleaner fuel, Bakersfield.com, Nov. 6, 2021, https://www.bakersfield.com/news/refinery-on-rosedale-makes-final-changes-for-switch-to-cleaner-fuel/article_36271b12-3e94-11ec-b8ac-df50c6c90b95.html (accessed Dec 14, 2021). **d.** Brelsford, R. 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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

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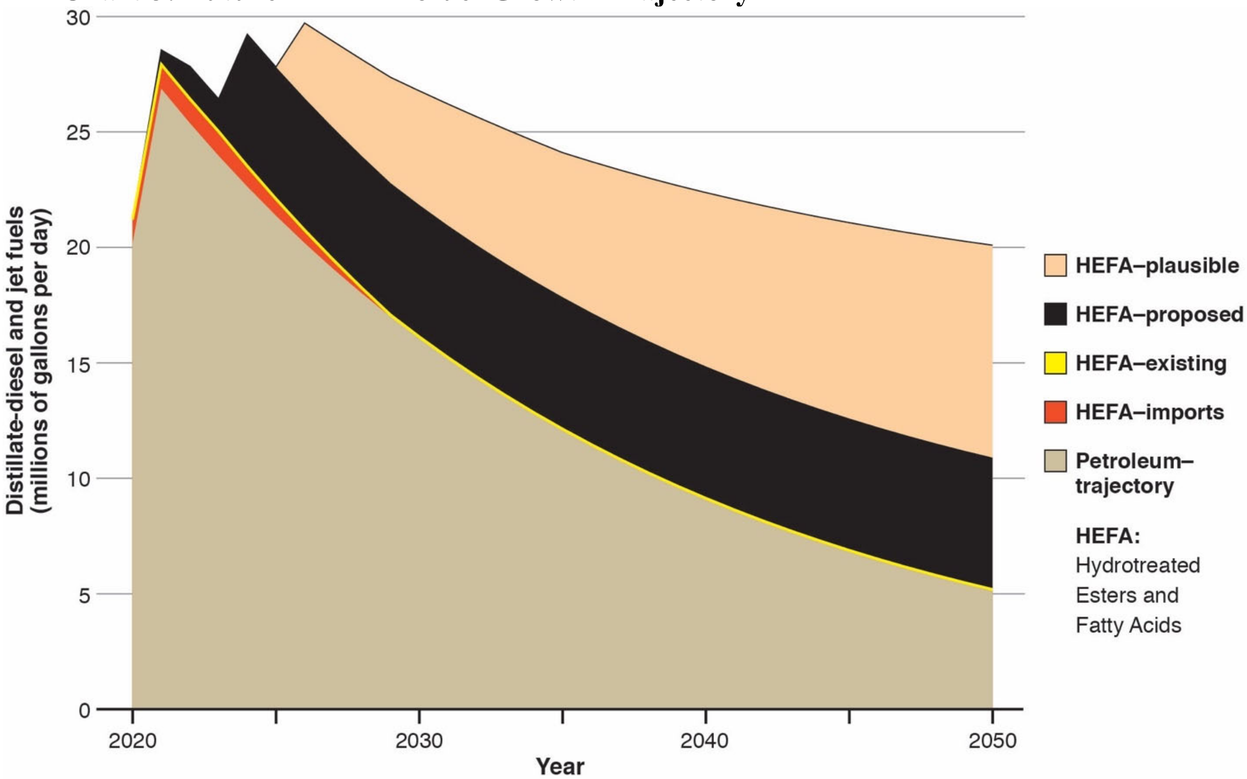
[261] Additional support for this section is provided in Karras, 2021a.

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

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

Chart 5: Future HEFA Biofuel Growth Trajectory



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

[263] Supporting Material Appendix for Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing; prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting, www.energy-re-source.com.

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

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

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

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

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264 *Id.*

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

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

267 *Id.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[278] The International Tanker Owners Pollution Federation (2016 spill statistics), p. 8.
[279] *Id.*
[280] *California Ocean and Coastal Economies*, National Ocean Economics Program (March 2015).
[281] Based on California Department of Fish and Wildlife and National Marine Fisheries Service data.
[282] *See, e.g., Incident Specific Preparedness Review M/V Cosco Busan Oil Spill in San Francisco Bay Report on Initial Response Phase*, Baykeeper, OSPR, NOAA, et al. (Jan. 11, 2008).

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

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

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

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

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

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283 Green *et al*., 2017.
284 *Id*.
285 *A Review of Double Hull Tanker Oil Spill Prevention Considerations*, Nuka Research & Planning Group, LLC. (Dec. 2009), p. 3, *available at* https://www.pwsrcac.org/wp-content/uploads/filebase/programs/oil_spill_prevention_planning/double_hull_tanker_review.pdf.

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

Instead, the DEIR claims that

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D. Recreational Impacts Are Potentially Significant

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

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

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

E. The Project Implicates Potential Utilities and Service System Impacts

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

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

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

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

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

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[291] Green *et al*. 2017.

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

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

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

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

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[292] *Id.*

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

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

G. Noise and Vibration Impact Analysis is Insufficient

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

H. Transportation and Traffic Impacts Analysis is Inadequate

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

I. Tribal Cultural Resources Impacts Analysis is Inadequate

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

J. The Project Risks Significant Environmental Justice and Economic Impacts

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

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

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

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

1. Public Trust Resources

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

2. Cross-Border Impacts

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

3. Terrorism Impacts

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

XII. CONCLUSION

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

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[295] OEHHA, Cal Enviro Screen 1.1 (amended), Statewide Zip Code Results, Rodeo, *available at* http://oehha.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=1d202d7d9dc84120ba5aac97f8b39c56.
[296] *Id.*
[297] *See* 2015 NOAA Fisheries of the United States.

Thank you for your consideration of these Comments.

Very truly yours,

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APPENDIX A

Karras, G., *Changing Hydrocarbons Midstream* (Karras, 2021a)

Changing Hydrocarbons Midstream

Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing

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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.

CONTENTS

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.

Changing Hydrocarbons Midstream

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 <u>Some different types of biofuel technologies</u>

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

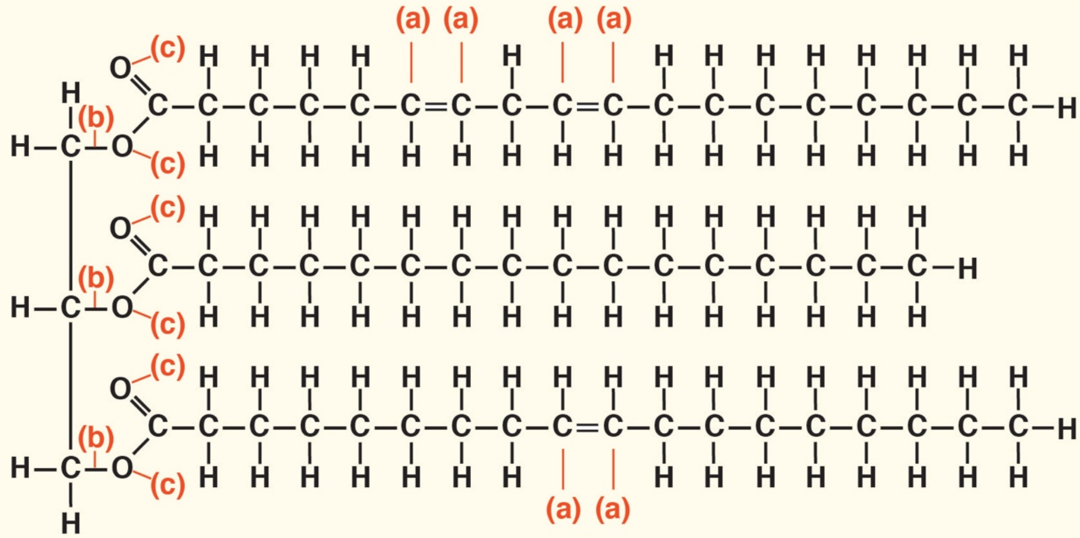
All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).[2 3 4 6] "Hydrotreating" signifies a hydro-conversion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

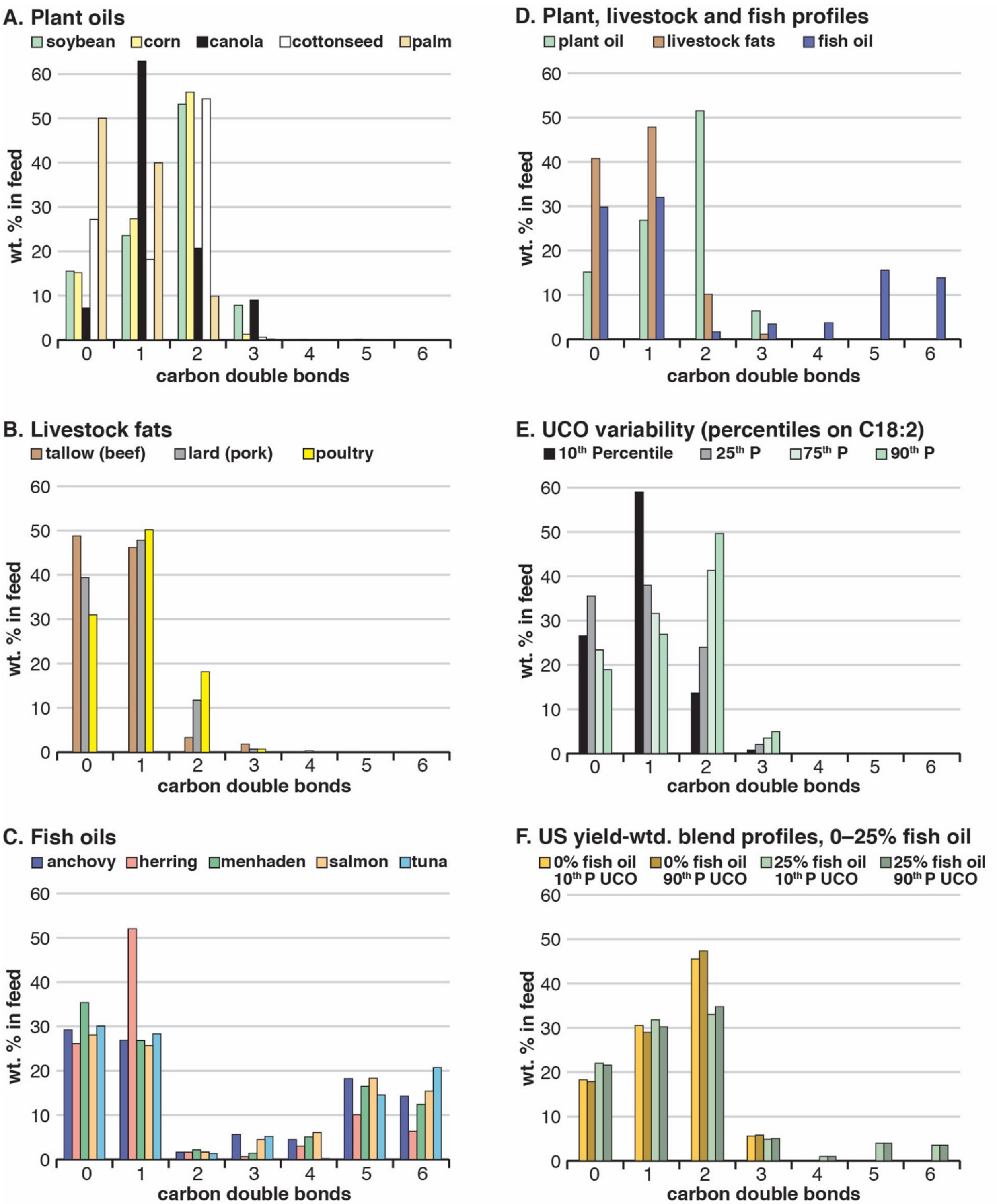
In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock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

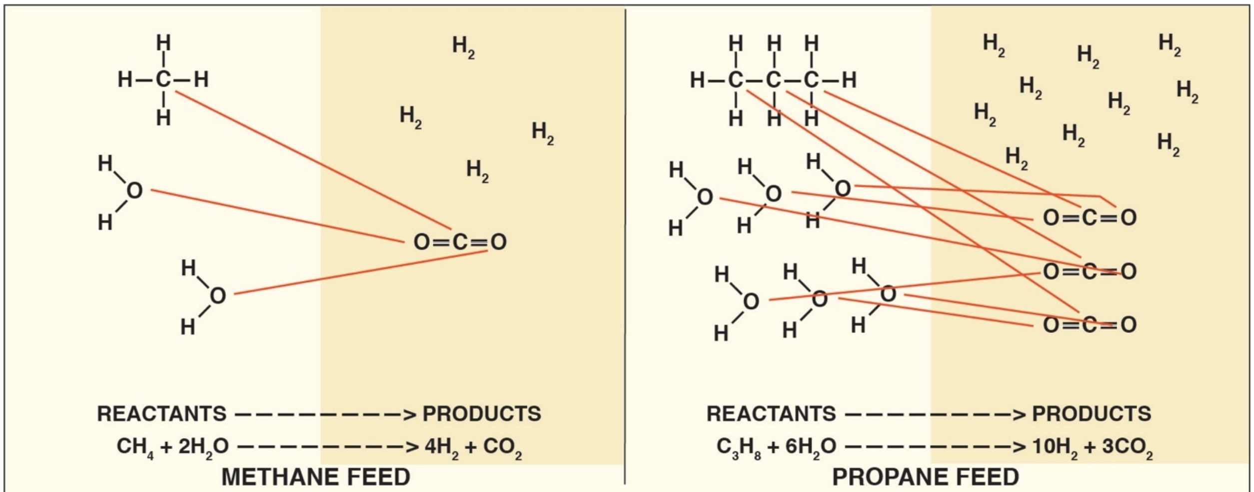


Diagram 2. Hydrogen steam reforming: reforming and shift reactions.

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 <u>State climate goals and pathways that HEFA biofuels growth could affect</u>

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]

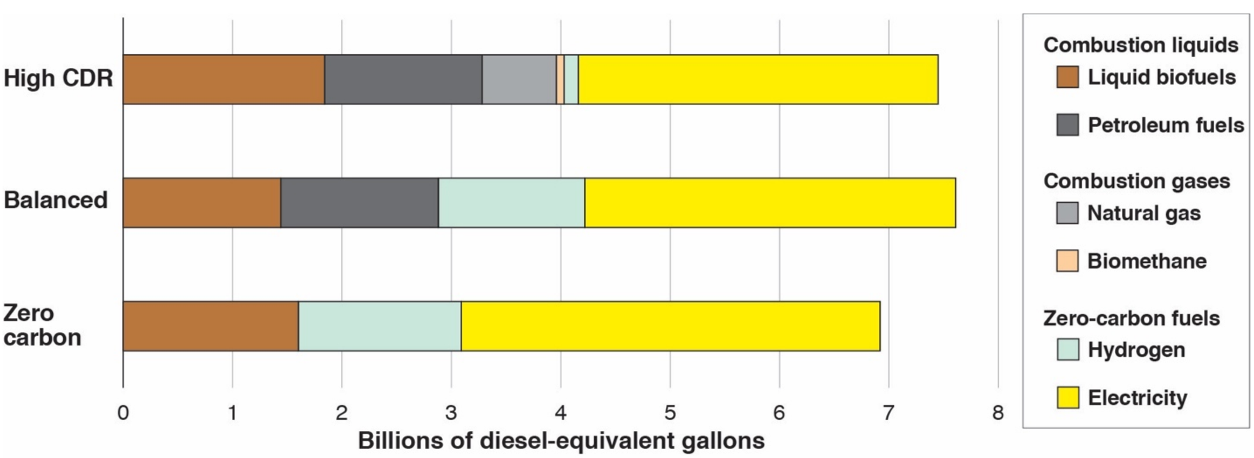
Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by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

4.1.3 <u>Electrolysis hydrogen benchmarks for systemic energy integration that affect the timing of choices between zero-emission *versus* liquid combustion fuels</u>

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]

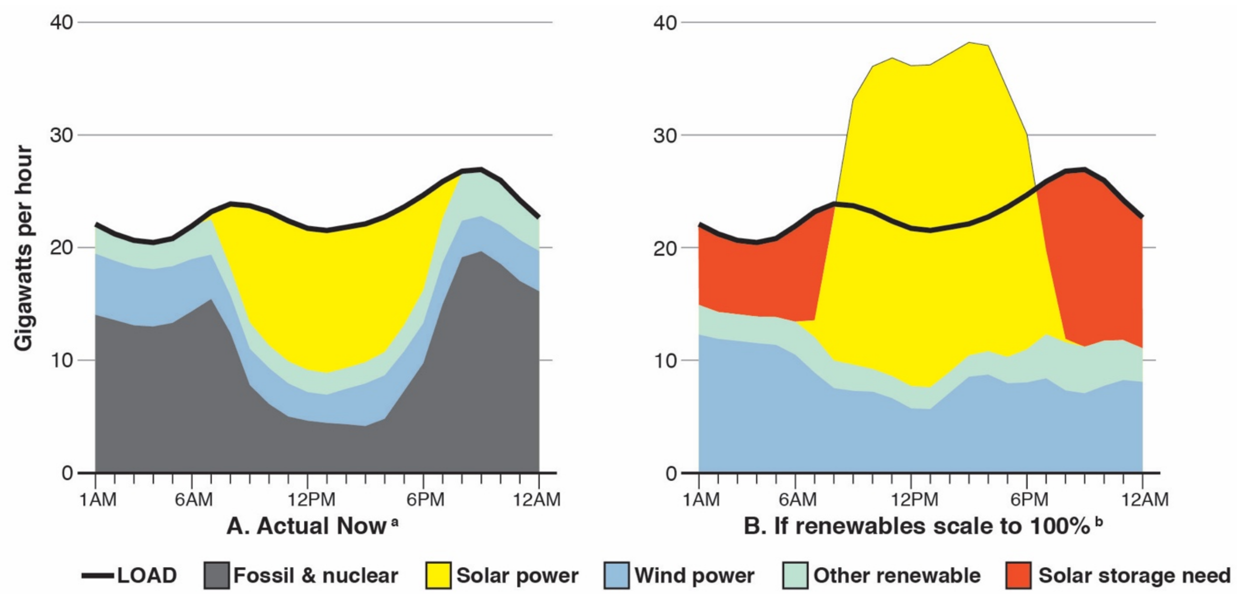
Renewable-powered electrolysis for future solar and wind power growth

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 <u>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</u>

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 <u>HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes</u>

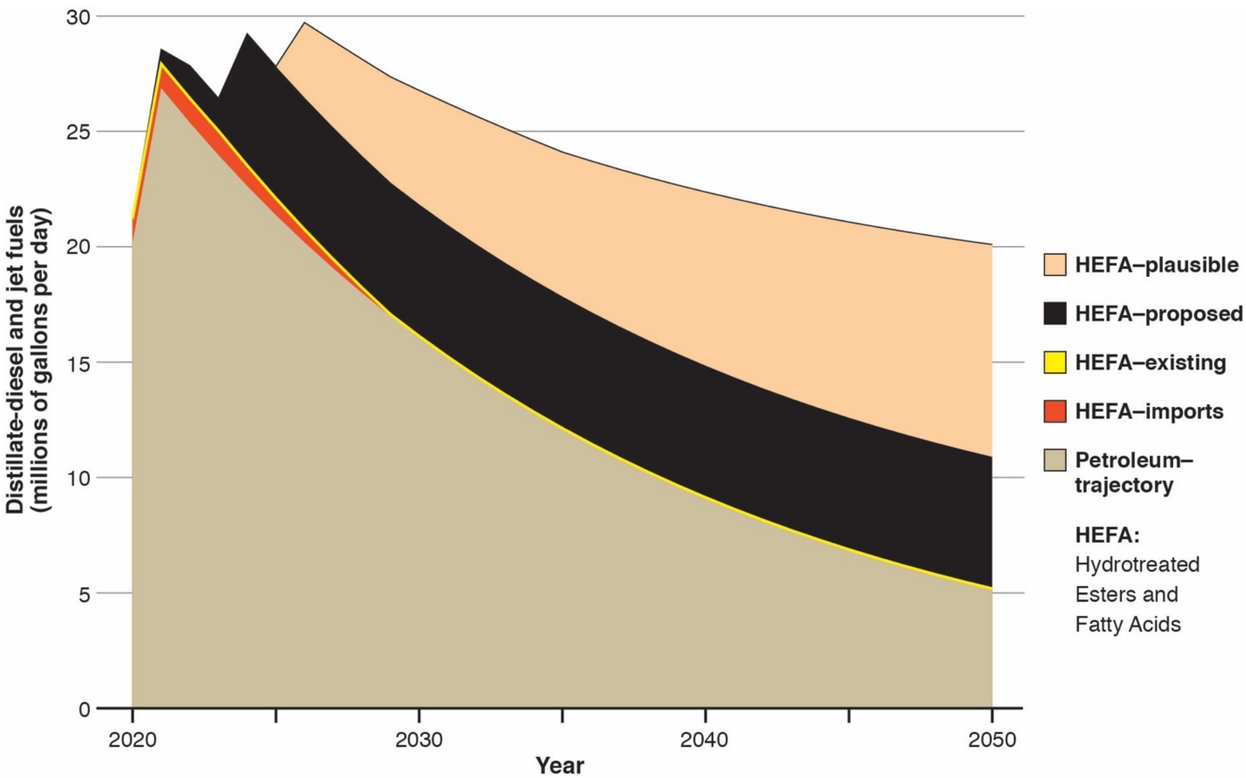
Proposed projects would exceed HEFA biofuel caps

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.

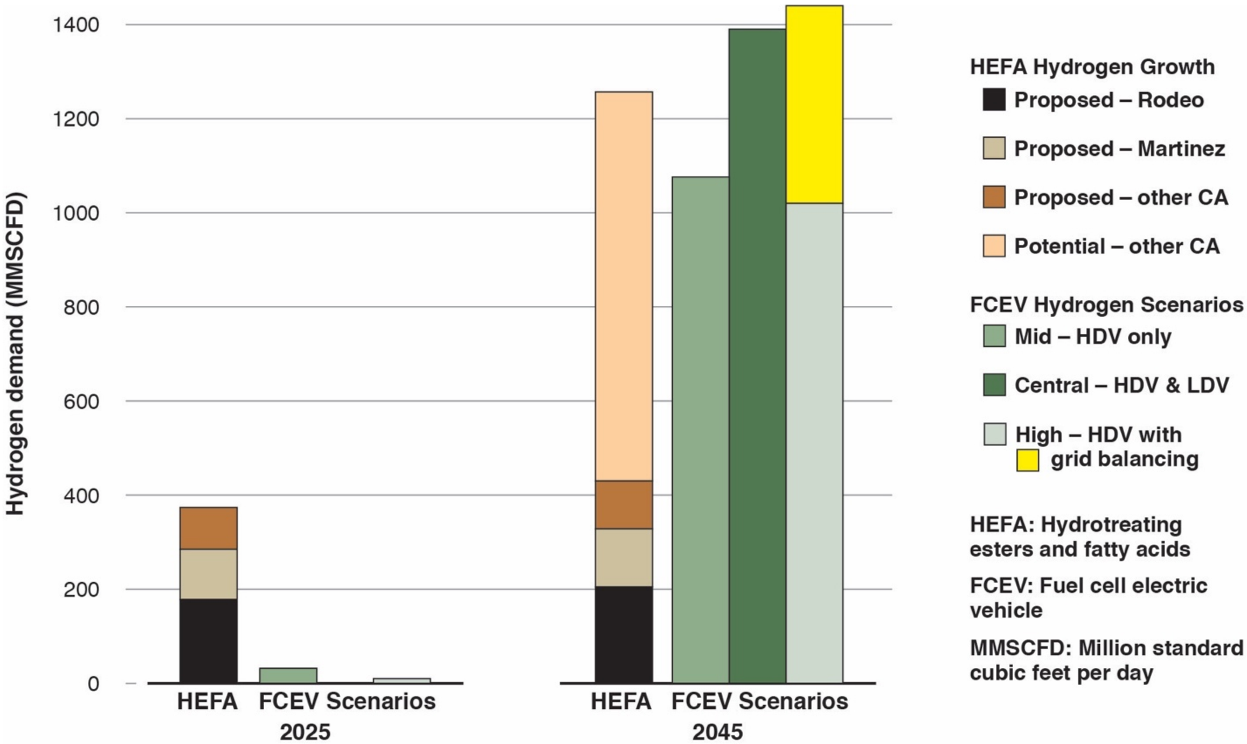
Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

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 <u>Use of electrolysis would facilitate development of hydrogen for potential future use in transportation and energy storage</u>

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 <u>Use of electrolysis could lessen transition impacts from future decommissioning of converted refineries</u>

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. *See* Table 2 below.

Table 2. Hydrogen demand for hydrodeoxygenation (HDO) of HEFA feedstocks, grouped by HDO jet fuel and diesel hydrocarbon yields. Data in kilograms hydrogen per barrel of feed fraction (kg H_2/b)

Feedstock grouping	Jet fraction (C8–C16)[a] HDO kg/b[c]	Jet fraction (C8–C16)[a] Sat kg/b[d]	Diesel fraction (C15–C18)[a] HDO kg/b[c]	Diesel fraction (C15–C18)[a] Sat kg/b[d]	Longer chains (> C18)[a b] HDO kg/b[c]	Longer chains (> C18)[a b] Sat kg/b[d]
High jet/high diesel						
Palm oil	4.38	< 0.01	4.77	0.64	3.52	0.15
Tallow fat	4.53	0.14	4.70	0.62	3.62	0.19
Poultry fat	4.58	0.25	5.04	0.92	3.99	0.67
Lard fat	4.43	0.11	4.84	0.75	5.39	1.68
UCO (10th Pc.)	4.52	0.20	5.02	0.92	4.30	0.75
Cottonseed oil	4.30	0.02	5.47	1.34	3.51	0.16
High jet/low diesel						
Menhaden oil	4.72	0.28	5.07	0.85	8.64	4.83
Herring oil	4.77	0.30	5.09	0.89	6.11	2.52
Anchovy oil	4.72	0.28	5.22	1.02	8.07	4.31
Tuna oil	4.67	0.24	4.81	0.64	8.06	4.34
Salmon oil	4.51	0.09	5.18	1.01	7.99	4.27
Low jet/high diesel						
Corn (DCO) oil	4.27	0.01	5.60	1.48	4.87	1.38
UCO (90th Pc.)	4.35	0.09	5.56	1.45	3.38	0.00
Soybean oil	4.28	0.01	5.70	1.59	3.31	0.00
Canola oil	4.35	0.07	5.45	1.37	3.98	0.55

a. Feedstock component fractions based on carbon chain lengths of fatty acids in feeds. **b.** Fatty acid chains with more than 18 carbons (> C18), which might be broken into two hydrocarbon chains in the jet fuel range (C8–C16) by intentional hydrocracking (IHC). **c.** HDO: hydrodeoxygenation; hydrogen consumed in HDO reactions, including saturation. **d.** Sat: saturation, H_2 needed to saturate carbon double bonds in the feedstock component, included in HDO total as well and broken out here for comparisons between types of feeds. *See* Table 8 for details of data, methods, and data sources. Note that fatty acids with 15–16 carbons (C15–C16) are included in both the jet fuel and the diesel fuel ranges. **UCO:** Used cooking oil, a highly variable feed; the 10th and 90th percentiles of this range of variability are shown.

2.3.3 Effects on process hydrogen demand

Table 2 shows process hydrogen demand for HDO, and the portion of HDO accounted for by saturation of carbon double bonds, for fractions of each feedstock. The important detail this illustrates is that saturation of carbon double bonds—especially in the larger-volume diesel fraction and, for fish oils, the longer chain fraction—explains most of the differences in direct effects on hydrogen demand among feeds. At less than 1% to more than half of HDO hydrogen demand, saturation drives differences in hydrogen demand among feed fractions (Table 2). Further, these differences peak in the diesel and longer chain fractions of feeds (*Id.*), and the combined volumes of these diesel and longer chain fractions are both high for all feeds and variable among feeds (Table 1).

Since HDO is an essential step in all HEFA processing strategies (Chapter 1), this evidence that process hydrogen demand varies among feeds because of the processing characteristics of whole feeds means we can compare hydrogen demand across processing strategies based on whole feeds. Table 3 shows results from this comparison across processing strategies.

Table 3. Hydrogen demand in the no intentional hydrocracking (No-IHC), Selective IHC and Isom-IHC processing strategies by feed grouping and feed. ***kg H_2/b:*** *kilograms hydrogen/barrel whole feed*

Feedstock grouping	No-IHC [a] (kg H_2/b)	Selective-IHC [b] (kg H_2/b)	Isom-IHC [c] (kg H_2/b)
High jet/high diesel			
Palm oil	4.79	5.79	6.60
Tallow fat	4.71	6.11	6.70
Poultry fat	5.03	6.28	6.85
Lard fat	4.85	6.13	6.65
UCO (10th P.)	5.01	6.37	6.83
Cottonseed oil	5.44	6.84	7.28
High jet/low diesel			
Menhaden oil	6.18	7.30	8.02
Herring oil	5.50	6.76	7.33
Anchovy oil	6.37	7.67	8.23
Tuna oil	6.29	7.62	8.16
Salmon oil	6.40	7.78	8.25
Low jet/high diesel			
Corn (DCO) oil	5.58	7.19	7.42
UCO (90th P.)	5.55	7.17	7.39
Soybean oil	5.68	7.33	7.52
Canola oil	5.40	7.16	7.24
Feed-wtd. Average	5.24	6.62	7.07

a. Intentional hydrocracking (IHC) is not used. **b.** Intentional hydrocracking (IHC) is selective because in this strategy HDO output is separately isomerized, and only the non-jet fuel hydrocarbons from HDO are fed to IHC. **c.** Isomerization and IHC are accomplished in the same process step in this strategy; all HDO output, including the jet fuel fraction, is fed to intentional hydrocracking in this strategy. *See* Table 8 for details of data, methods, and data sources;[1] Table 7 for world feed data used to derive feed-weighted averages. **UCO:** Used cooking oil, a highly variable feed; 10th and 90th percentiles of range shown.

2.3.4 Interactions between feedstock and processing choices

Feedstock and process strategy choices combined can impact HEFA process hydrogen demand dramatically (Table 3). As expected, IHC increases hydrogen demand for all feeds, however, feed-driven and process strategy-driven effects overlap. The maximum feed-driven impact in the No-IHC strategy (6.40 kg H_2/b) exceeds the minimum (5.79 kg H_2/b) in the Selective-IHC strategy (*Id.*). Similarly, the maximum feed-driven impact in the Selective-IHC strategy (7.78 kg H_2/b) exceeds the minimum (6.60 kg H_2/b) in the Isom-IHC strategy (*Id.*). Hydrogen demand increases by approximately 75% from the lowest impact (4.71 kg H_2/b) to the highest impact (8.25 kg H_2/b) combination of feedstock and processing strategy (*Id.*).

Feed rankings for hydrogen demand differ from feed rankings for jet fuel yield (tables 1, 3). Palm oil ranks at the top for jet fuel yield and at or near the bottom for hydrogen demand while in contrast, fish oils are among the highest ranked feeds for both jet yield and hydrogen demand. Livestock fats are among the highest ranked feeds for jet fuel yield and among the lowest ranked feeds for hydrogen demand. The lowest ranked feeds for jet fuel yield, soybean and canola oils, are medium-ranked to high-ranked feeds for hydrogen demand.

Relatively lower hydrogen demand for palm oil and livestock fats across the columns in Table 3 further illustrates how interactions of feedstock and processing strategies can contribute to increased jet fuel yields. For example, the relative Isom-IHC hydrogen demand reduction achievable by switching from soybean oil to tallow (-0.82 kg/b; -10.9%) or from soybean oil to palm oil (-0.92 kg/b; -12.2%) can help to support the highest jet fuel yield processing strategy in situations where refinery hydrogen production capacity is marginally limited.

Results in Table 3 also reveal that some feedstocks switch rankings between the Selective-IHC strategy and other processing strategies. In one example, canola oil feedstock demands more hydrogen than cottonseed oil feedstock for Selective-IHC but slightly less than cottonseed oil for the No-IHC and Isom-IHC strategies (Table 3). This corresponds to the greater fraction of canola oil than cottonseed oil sent to intentional hydrocracking for the Selective-IHC strategy (*see* Table 1, > C16 vol. %).

Another example: Only some 57.7% of the total Menhaden oil feed volume goes to intentional hydrocracking for Selective-IHC, as compared with 88.3% of the soybean oil feed (*Id.*). Consequently, Menhaden oil demands less hydrogen than soybean oil for Selective-IHC but more hydrogen than soybean oil for the other processing strategies (Table 3).

Putting these direct and indirect feed-driven effects together, consider switching from soybean oil to tallow for Selective-IHC at a 50,000 to 80,000 b/d refinery—which is in the range of projects now proposed in California.[2] The direct effect on HDO from this soy oil-to-tallow switch, shown in the No-IHC column of Table 3 (-0.97 kg H_2/b), carries over to Selective-IHC. The indirect effect sends 21.6% less of the total tallow feed to hydrogen-intensive cracking for Selective IHC than that of soy oil (Table 1, > C16 fractions), further boosting hydrogen savings from the switch to -1.22 kg/b on total feed (Table 3). At feed rates of 50,000–80,000 b/d, this might save the refiner construction and operating costs for 61,000 to 97,600 kg/d of hydrogen capacity. Expressed as volume in millions of standard cubic feet per day (MMSCFD), that is the equivalent of a 24 to 38 MMSCFD hydrogen plant.

At the same time that switching from soy with No-IHC to tallow with Selective-IHC could enable the higher-yield processing strategy, however, net process hydrogen demand would increase by 0.43 kg/b (Table 3), an increase in this example of 8.4 to 13.5 MMSCFD.

Thus, examining feed and processing interactions reveals that switching to feeds with higher jet-range fractions, lower HDO hydrogen demand, or both enables refiners with limited hydrogen supplies to use intentional hydrocracking and thereby further boost jet fuel yields. More broadly, these results show refiners can make more HEFA jet fuel from some feedstocks than from others, but that doing so could result in substantially increased hydrogen demand for some combinations of feedstock and processing choices.

3. Does switching from one HEFA feedstock to another change processing carbon intensity differently when refiners target jet fuel instead of diesel production?

Switching feedstocks and production targets can affect the per-barrel emissions—the *carbon intensity*—of HEFA refining dramatically. The vast majority of direct CO_2 emission from HEFA refining emits from petroleum refinery steam reformers that refiners repurpose to supply HEFA process hydrogen demand.[2] The reformer emissions further increase with increasing hydrogen production.[2] As shown in Chapter 2, refiners could switch feeds to boost HEFA jet fuel yield in ways that increase refinery hydrogen demand differently compared with targeting HEFA diesel yield. This chapter evaluates the carbon intensity (CI) impacts of HEFA refining that could result from targeting HEFA jet fuel yield instead of diesel yield, and weighs their significance against the CI of petroleum refining.

3.1 CO_2 co-production and emission from hydrogen production by steam reforming

3.1.1 How steam reforming makes hydrogen

Steam reforming is a fossil fuel hydrogen production technology that co-produces CO_2. The process reacts a mixture of superheated steam and hydrocarbons over a catalyst to form hydrogen and CO_2. Hydrocarbons used include methane from natural gas, and it is often called steam methane reforming (SMR), but crude refiners use hydrocarbon byproducts from refining such as propane, along with methane from purchased natural gas, as feeds for the steam reformers that they could repurpose for HEFA processing.

3.1.2 How steam reforming emits CO_2

Both its CO_2 co-product and CO_2 formed in its fuel combustion emit from steam reforming. An energy-intensive process, steam reforming burns fuel to superheat process steam and feed, and burns more fuel for energy to drive pumps and support process reactions. Steam reforming fuel combustion emissions are reformer-specific and vary by plant. Based on verified permit data for 11 San Francisco Bay Area crude refinery steam reforming plants, we estimate median fuel combustion emissions of approximately 3.93 grams of CO_2 emitted per gram of hydrogen produced (g CO_2/g H_2), conservatively assuming methane fuel.[2] Co-product emissions are larger still, and vary by feed, with approximately 5.46 g CO_2/g H_2 emitting from methane feed and 6.56 g CO_2/g H_2 emitting from propane feed.[2] The coproduct and combustion emissions are additive.

3.1.3 Steam reforming CO_2 emission estimate

HEFA refinery steam reforming can be expected to use a feed and fuel mix that includes the propane byproduct from the process reactions discussed in Chapter 1 and natural gas methane. Based on process chemistry we conservatively assume 79% methane/21% propane feed with 100% methane fuel. From these figures we estimate typical HEFA steam reforming emissions of approximately 9.82 g CO_2/g H_2. This estimate is for repurposed crude refinery steam reformers, which are aging and may not be as efficient as newer steam reformers.[2] For context, however, our estimate is within 2.5% of a recent independent estimate of median emissions from newer merchant steam methane reforming plants, when compared on a same-feed basis.[2]

Thus, repurposed refinery steam reforming emits CO_2 at nearly ten times its weight in hydrogen supplied. With the high hydrogen demand for HEFA processing shown in Chapter 2, that is a problem. Since steam reforming emissions increase with increased production to meet increased hydrogen demand, the refining CI values reported below are based on the emission factor described above (9.82 g CO_2/g H_2) and the hydrogen demand data from Chapter 2.

3.2 Feedstock effects on CI resulting from HDO hydrogen demand

Hydrodeoxygenation (HDO) is an essential step, and is the major hydrogen consuming step, in all HEFA processing strategies (chapters 1 and 2). The data in Table 4 represent the HEFA processing strategy that uses HDO without intentional hydrocracking (No-IHC).

3.2.1 Feedstock HDO chemistry impact on HEFA refining CI

Table 4 shows effects of feedstock HDO chemistry on HEFA steam reforming emissions. Steam reforming-driven CI (kg/b: kg CO_2 per barrel feed) is substantially higher for whole feeds than for their jet fuel fractions. This is because the non-jet fractions need more hydrogen to saturate carbon double bonds and their combined volumes are larger than that of the jet fuel fraction (tables 1 and 2). Further, the extent of these differences between fractions varies among feeds (*Id.*). This is why feeds change ranks between the columns in Table 4. For example, the jet fuel fraction of palm oil has higher CI than that of soybean oil even though the whole feed data show that soybean oil is a higher CI feed. This variability among feed fractions also is why fish oil CI is high for both the jet fraction and the whole feed.

3.2.2 Need to account for whole feed impact

Does Table 4 show that palm oil could be a higher refining CI feed than soybean oil? No. Since the HDO step is essential for removing oxygen from the whole feed to co-produce both HEFA jet fuel and HEFA diesel, choosing any feed results in the CI impact of that whole feed.

Table 4. Hydrogen steam reforming emissions associated with the jet fuel fraction *v.* whole HEFA feeds in the HDO (No IHC) refining strategy; comparison of feed ranks by emission rate.

Jet fuel fraction (C8–C16)		Whole feed (≥ C8)	
Feed (rank)	CO_2 (kg/b feed)	Feed (rank)	CO_2 (kg/b feed)
Herring oil	46.8	Salmon oil	62.8
Menhaden oil	46.4	Anchovy oil	62.5
Anchovy oil	46.4	Tuna oil	61.7
Tuna oil	45.9	Menhaden oil	60.7
Poultry fat	45.0	Soybean oil	55.8
Tallow fat	44.5	Distillers corn oil	54.8
UCO (10th Percentile)	44.4	UCO (90th Percentile)	54.4
Salmon oil	44.3	Herring oil	54.0
Lard fat	43.5	Cottonseed oil	53.4
Palm oil	43.0	Canola oil	53.1
Canola oil	42.7	Poultry fat	49.4
UCO (90th Percentile)	42.7	UCO (10th Percentile)	49.2
Cottonseed oil	42.2	Lard fat	47.6
Soybean oil	42.0	Palm oil	47.1
Distillers corn oil	41.9	Tallow fat	46.2

C8–C16: fatty acid chains with 8 to 16 carbon atoms. **≥ C8:** fatty acid chains with 8 or more carbon atoms. **Menhaden:** a fish. **UCO:** used cooking oil, a variable feed; 10th and 90th percentiles shown. Data from Table 2 at 9.82 g CO_2/g H2 steam reforming.

While the jet fuel fraction data in this table helps to inform why feed quality impacts refining CI, we need to account for those CI impacts of whole feeds shown in Table 4.

3.2.3 High-jet feeds can increase or decrease HDO-driven CI

HDO-driven CI findings for whole feeds reveal mixed CI results for high-jet fuel yield feedstocks in No-IHC processing. Fish oils rank highest for steam reforming-driven CI while livestock fats and palm oil rank lowest (Table 4). Thus, for this processing strategy, switching feeds to boost jet fuel yield can increase or decrease refining CI. However, No-IHC also is the processing strategy that HEFA refiners use to maximize diesel yield rather than jet fuel yield. Feedstock quality interacts with other processing choices in different ways that could further boost HEFA refining CI along with jet fuel yield, as shown below.

3.3 Feedstock effects on CI resulting from Selective-IHC hydrogen demand

3.3.1 Process strategy impact of high-jet feeds

High jet yield feeds result in less input to Selective-IHC, enabling marginally hydrogen-limited refiners to further boost jet fuel yield via Selective-IHC, but this requires additional hydrogen (chapters 1 and 2). Intentional hydrocracking (IHC) thus increases hydrogen steam reforming rates and emissions, increasing refining CI for all feeds, as shown in Table 5. This impact overlies the HDO impact, so that feed CI values overlap between columns. For example, the tuna oil No-IHC CI (61.7 kg/b) exceeds the tallow Selective-IHC CI (60.0 kg/b), and the anchovy oil Selective-IHC CI (75.3 kg/b) exceeds the soy oil Isom-IHC CI (73.9 kg/b).

Table 5. Hydrogen steam reforming emissions from the No-IHC, Selective-IHC, and Isomerization IHC refining strategies: comparisons of whole HEFA feed ranks by emission rate.

No-IHC		Selective-IHC		Isomerization-IHC	
Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)
Salmon oil	62.8	Salmon oil	76.4	Salmon oil	81.0
Anchovy oil	62.5	Anchovy oil	75.3	Anchovy oil	80.8
Tuna oil	61.7	Tuna oil	74.8	Tuna oil	80.1
Menhaden oil	60.7	Soybean oil	72.0	Menhaden oil	78.8
Soybean oil	55.8	Menhaden oil	71.6	Soybean oil	73.9
Corn oil–DCO	54.8	Corn oil-DCO	70.6	Corn oil-DCO	72.8
UCO 90^{th} P.	54.4	UCO 90^{th} P.	70.4	UCO 90^{th} 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 10^{th} P.	62.5	Poultry fat	67.2
UCO 10^{th} P.	49.2	Poultry fat	61.7	UCO 10^{th} 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, 10^{th}, 90^{th} percentiles shown. **DCO:** distillers corn oil. Figures shown exclude emissions associated with H_2 losses, depropanation, and inadvertent cracking. Data from Table 3 at 9.82 g CO2/g H2 steam reforming.

3.3.2 Feed chemistry effects on feed rankings for CI

Feedstock CI rankings differ between No-IHC and Selective-IHC processing (Table 5). This is a feed quality impact driven primarily by the different volumes of non-jet fractions sent to IHC among feeds. It boosts the CI of soybean oil from 4.9 kg/b below to 0.4 kg/b above the CI of menhaden oil with the addition of Selective-IHC (*Id.*). With 88.3% of its volume outside the jet fuel range compared with 57.7% of menhaden oil (Table 1, > C16 fractions), soy oil sends 30.6% more feed to Selective-IHC than menhaden oil. More IHC feed requires more hydrogen, boosting steam reforming emissions more with soy than with menhaden oil. Similarly, canola oil sends 27.9% more feed to Selective-IHC than herring oil (*Id.*). This boosts canola oil CI from 0.9 kg/b below to 3.9 kg/b above herring oil CI with the addition of Selective-IHC (Table 5).

3.3.3 How livestock fat feeds could affect soy oil and canola oil refining CI

When switching from soy or canola oil to livestock fat enables a refiner to boost jet fuel yield by repurposing its refinery for Selective-IHC processing, that intentional hydrocracking can boost jet yield from soy and canola oil feeds as well. Thus, instead of shutting down when, for any reason at any time, livestock fat becomes too scarce or expensive, the refiner could make jet fuel by going back to soybean oil or canola oil feedstock. This could increase refining CI by 16.2 kg/b (29%) for soy oil, and 17.2 kg/b (32%) for canola oil, based on our results for the Selective-IHC *versus* No-IHC processing strategies in Table 5.

3.4 Feedstock effects on CI resulting from Isom-IHC hydrogen demand

Livestock fat and palm oil could maximize jet fuel yield by enabling Isom-IHC processing, since these feeds minimize HDO hydrogen demand (chapters 1 and 2). Their relatively lower non-jet fractions do not contribute to this effect on Isom-IHC because, in contrast to Selective-IHC, Isom-IHC processes the entire feed stream output from HDO. Direct effects of feed quality variability on Isom-IHC cracking are relatively weak, since HDO both saturates and removes oxygen from Isom-IHC inputs. Thus, the relative feed rankings for CI from No-IHC processing carry over to the Isom-IHC feed rankings with only minor differences (Table 5). However, by cracking of the entire HDO output, Isom-IHC further boosts hydrogen demand, thus hydrogen steam reforming emissions, resulting in the highest HEFA refining CI for all feeds (*Id.*).

Across feeds and process options, from the lowest to the highest impact combinations of feeds and processing, HEFA refining CI increases by 34.8 kg CO_2/b (75%), and CI increases in 122 (79.7%) of 153 feed switching combinations that could boost jet fuel yield (tables 1, 3, 5).

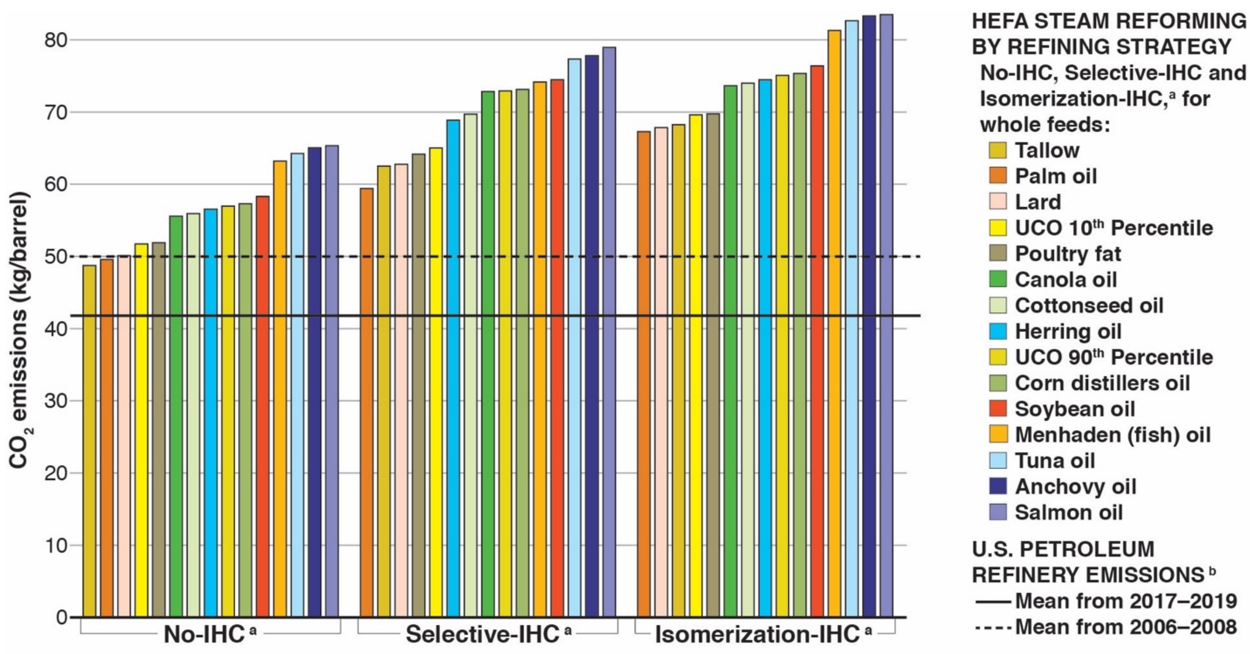
3.5 Comparison with petroleum refining CI by feedstock and processing strategy

Chart 1 plots results for feedstock-related impacts on the variability of HEFA refining CI from HEFA steam reforming emissions against the CI of U.S. petroleum refining. Our results in Table 5 are shown by processing strategy and, within each strategy, each feed is represented by a color-coded column. The height of the column represents the contribution of steam reforming to HEFA refining CI for that particular feed and processing strategy. The solid black line shown at approximately 41.8 kg/b (kg CO_2/barrel crude processed) represents the average U.S. petroleum refining CI from 2015 through 2017.[6] We use this (41.8 kg/b) as our benchmark. For added context, average U.S. petroleum refining CI from 2006–2008,[7] a period when the U.S. refinery crude slate was denser and higher in sulfur than during 2015–2017[8] resulting in higher historic U.S. crude refining industry CI,[7] is represented by the dashed line at 50 kg/b in the chart.

Please note what HEFA emissions Chart 1 does and does not show. It shows HEFA refining steam reforming emissions only. This helps us focus on our question about refining CI impacts from HEFA feedstock switching to target jet fuel, which are directly related to HEFA steam reforming rates. It *does not* show total direct emissions from HEFA refining.

3.5.1 HEFA refining CI impacts are significant compared with crude refining

Other HEFA refining emissions besides those from steam reforming—from fuel combustion to heat and pressurize HEFA hydro-conversion reactors, precondition and pump their feeds, and distill and blend their products—could add roughly 21 kg/b of additional HEFA refining CI.[2] Thus, for a rough comparison of petroleum refining CI with total HEFA refining CI, imagine adding 21 kg/b to the top of each column in Chart 1. HEFA refining CI approaches or exceeds *double* the CI of petroleum refining. Clearly, expanding HEFA jet fuel would increase the CI of hydrocarbon fuels processing substantially.



1. HEFA Steam Reforming Emissions *v.* Total U.S. Petroleum Refining Emissions, kg CO_2/barrel feed input.

a. HEFA steam reforming emissions only: values shown exclude CO_2 emitted by other HEFA refining process and support equipment. This contrasts with the petroleum refining emissions shown, which include all direct emissions from crude refining. Including all direct emissions from HEFA refining could increase the HEFA estimates shown by approximately 21 kg/barrel.[2] The "No-IHC" strategy excludes intentional hydrocracking (IHC); the "Selective-IHC" strategy adds emission from producing hydrogen consumed by intentional hydrocracking of feed fractions comprised of hydrocarbons outside the jet fuel range; the "Isomerization-IHC" strategy adds emissions from intentional hydrocracking of whole feeds in the isomerization step of HEFA fuels production. HEFA data shown include feed-driven emissions in Table 5 plus additional steam reforming emissions (2.5 kg/b) from producing the additional hydrogen that is lost to unintended side-reaction cracking, solubilization, scrubbing and purging (*see* Table 8).[1]

b. U.S. petroleum refinery emissions including total direct CO_2 emitted from steam reforming and all other petroleum refinery process and support equipment at U.S. refineries. Mean from 2015 through 2017 based on total refinery emissions and distillation inputs reported by the U.S. Energy Information Administration (EIA).[6] Mean from 2006 through 2008 represents a period of historically high-carbon U.S. refining industry crude inputs.[7,8]

3.5.2 High-jet feed impacts on processing targeting jet fuel can increase refining CI

Feeds that enable intentional hydrocracking to boost jet fuel yield could increase HEFA refining CI significantly (Chart 1). Here we report feed switching CI increments compared with No-IHC processing of soy and canola oils to target diesel yield (*see* Table 5) as percentages of our petroleum crude refining benchmark: Switching to Selective IHC with anchovy and salmon oils increases CI by 47% to 56% (of crude refining CI) while switching to Selective IHC with menhaden oil increases CI by 38% to 44%. Switching to Isom-IHC with tallow increases CI by 24% to 30% while switching to Isom-IHC with palm oil increases HEFA refining CI by 21% to 28% of crude refining CI. Switching to Selective-IHC with tallow increases CI by 10% to 17%. Only Selective-IHC with palm oil has similar CI to that of No-IHC with soy oil (+3%).

3.5.3 High-jet feed CI impacts are mixed in processing targeting HEFA diesel yield

Compared with No-IHC processing of soy or canola oils, which are the combinations of processing and feeds that maximize HEFA diesel yield, No-IHC with fish oils could increase refining CI while No-IHC with palm oil or livestock fats could decrease CI. For example, switching to anchovy oil could increase No-IHC HEFA refining CI over that of canola and soy oils by 16% to 23% of crude refining CI while switching to tallow could decrease it by 16% to 23% of crude refining CI. But there is a caveat to those estimates.

In theory, feeding tallow to No-IHC processing could boost jet fuel yield to one-third of feedstock volume (Table 1) while lowering CI by 6.8 or 9.5 kg/b below canola or soy oil in No-IHC processing, the strategies refiners use to maximize HEFA diesel yield. However, this would require three barrels of tallow feed per barrel of jet fuel yield, emphasizing a crucial assumption about HEFA biofuel as a sustainable jet fuel solution—it assumes a sustainable feedstock supply. That assumption could prove dangerously wrong, as shown in Chapter 4.

4. HEFA jet fuel feedstock and carbon sinks: Could the feedstocks that maximize HEFA jet fuel instead of diesel yield have comparatively high indirect climate impacts?

Increasing demand for limited supplies of feedstocks that refiners could use to boost HEFA jet fuel yield and make more HEFA jet fuel risks increasing deforestation and other serious indirect climate impacts. HEFA biofuel feedstocks are purpose-derived lipids also needed for food and other uses,[9 10] are globally traded, and can increase in price with increased biofuel demand for their limited supply.[2] Ecological degradation caused by expanded production and harvesting of the extra lipids for biofuels has, in documented cases, led to emissions from natural carbon sinks due to biofuels. Those emissions have traditionally been labeled as an "indirect land use impact," but as shown above, refiners seeking to maximize HEFA jet fuel production also could use fish oil feedstocks. The term "indirect carbon impacts," meant to encompass risks to both terrestrial and aquatic carbon sinks, is used in this chapter.

4.1 <u>Natural carbon sinks that HEFA jet fuel feedstock acquisition could affect</u>

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.

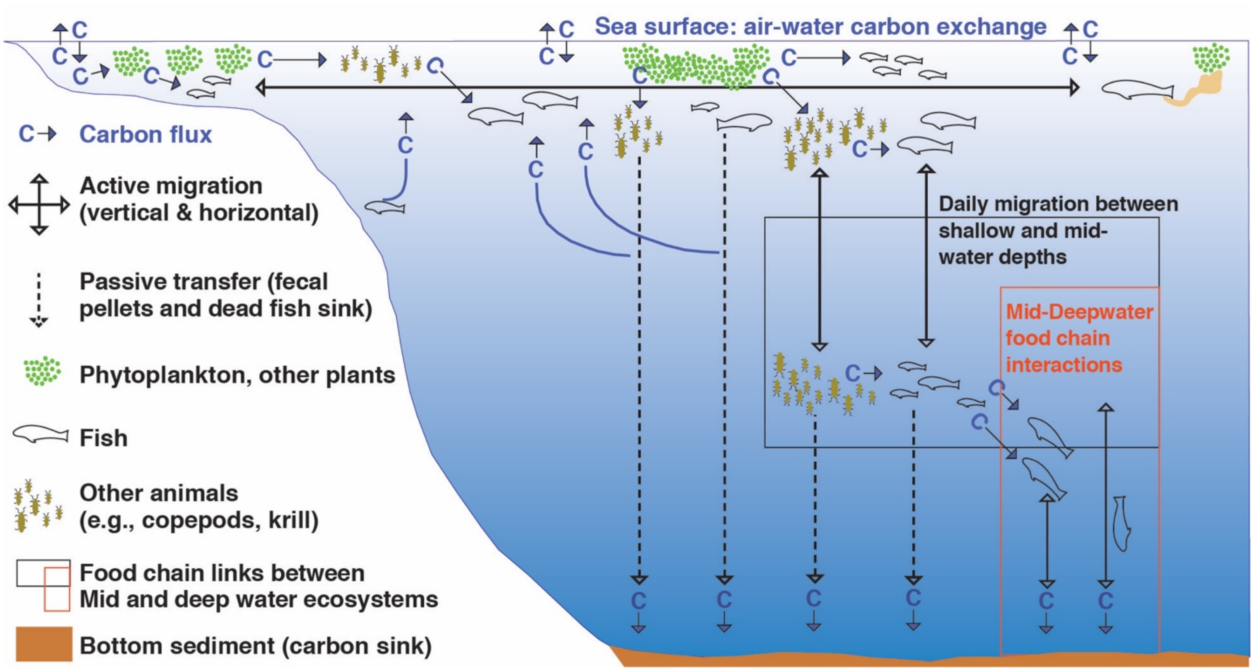


Illustration 1. Biological pump to the deep oceans carbon sink

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 <u>Historic impact assessments for high jet fuel yield HEFA feedstocks</u>

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. <u>*See*</u> 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. <u>*See*</u> 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 Priorities for future work

5.2.1 Cellulose biomass alternatives—what is holding them back?

Cellulosic residue biomass such as cornstalks, currently composted yard cuttings, or sawdust can be used as feedstock by alternative technologies which qualify as SAF.[19 35] Using this type of feedstock for SAF could lessen or avoid the indirect carbon impacts from excessive HEFA jet fuel demand for limited lipids biomass that are described in Chapter 4. Indeed, economy-wide analyses of the technologies and measures to be deployed over time for climate stabilization suggest prioritizing cellulosic biomass, to the extent that biofuels will be needed in some hard-to-decarbonize sectors.[42 57 58] Despite its promise, however, the deployment of cellulosic distillate biofuel has stalled compared with HEFA biofuel. Less clear are the key barriers to its growth, the measures needed to overcome those barriers, and whether or not those measures and the growth of cellulosic jet fuel resulting from them could ensure that SAF goals will be met sustainably. This points to a priority for future work.

5.2.2 Alternatives to burning jet fuel—need and potential to limit climate risks

Even complete replacement of petroleum jet fuel with SAF biofuel combustion would result in ongoing aviation emissions, and would thus rely on additional and separate carbon capture-sequestration to give us a reasonable chance of stabilizing our climate. At the current jet fuel combustion rate the scale of that reliance on "negative emission" technologies, which remain unproven at that scale, is a risky bet. Meanwhile, besides alternative aircraft propulsion systems, which are still in the development stage, there are alternatives to jet fuel combustion which are technically feasible now and can be used individually or in combination.

Technically feasible alternatives to burning jet fuel include electrified high-speed rail, fuel cell powered freight and shipping to replace air cargo, and conservation measures such as virtual business meetings and conserving personal air-miles-traveled for personal visits. While we should note that such travel pattern changes raise social issues, so does climate disruption, and most people who will share our future climate are not frequent fliers. Importantly as well, public acceptance of new travel alternatives is linked to experiencing them. Thus, biofuel limitations, climate risks, and human factors suggest needs to prioritize the development and deployment of alternatives to petroleum jet fuel that do not burn carbon.

5.2.3 Limited safety data record for flying with new fuels

Jet biofuels appear to differ from petroleum jet fuels in their cold flow properties at high altitude, combustion properties, and potential to damage fuel system elastomer material.[19] Those that can be used as SAF have been approved subject to blending limits, which permit SAF to be "dropped-in" to conventional jet fuel up to a maximum of 50% of the blend.[59] All seven types of biofuels approved for SAF are subject to this condition.[59] SAF/petroleum jet fuel blends that do not meet this condition are deemed to present potential safety issues.[59]

However, remarkably limited historical use of SAF (§4.3.1) has resulted in a limited data record for assessing its safety in actual operation. That is important because new hazards which result in dangerous conditions over long periods of operation have repeatedly been discovered only by rigorous post-operational inspection or post-incident investigation, the histories of both industrial and aviation safety oversight show. There is an ongoing need to ensure flight safety risks of biofuels are closely monitored, rigorously investigated, transparently communicated, and proactively addressed by "inherent safety measures"[60] designed to eliminate any specific hazards identified by that future work.

Table 8. Data and methods table for feed-specific estimates.[a]

Fatty acid (FA) in HEFA oil feed common name	Shorthand	Formula[b]	Density (kg/b)*	Oxygen content (wt. %)*	Carbon double bonds	FA-specific hydrogen inputs: Deoxygenation[c] (kg H_2/b)	FA-specific hydrogen inputs: Saturation[d, e] (kg H_2/b)
Caprylic Acid	C8:0	$C_8H_{16}O_2$	145	22.2	0	8.09	0.00
Capric Acid	C10:0	$C_{10}H_{20}O_2$	142	18.6	0	6.65	0.00
Lauric Acid	C12:0	$C_{12}H_{24}O_2$	140	16.0	0	5.63	0.00
Myristic Acid	C14:0	$C_{14}H_{28}O_2$	137	14.0	0	4.84	0.00
Myristoleic Acid	C14:1	$C_{14}H_{26}O_2$	143	14.1	1	5.10	1.27
Pentadecanoic Acid	C15:0	$C_{15}H_{30}O_2$	134	13.2	0	4.45	0.00
Palmitic Acid	C16:0	$C_{16}H_{32}O_2$	135	12.5	0	4.26	0.00
Palmitoleic Acid	C16:1	$C_{16}H_{30}O_2$	142	12.6	1	4.50	1.13
Margaric Acid	C17:0	$C_{17}H_{34}O_2$	136	11.8	0	4.04	0.00
Stearic Acid	C18:0	$C_{18}H_{36}O_2$	134	11.2	0	3.79	0.00
Oleic Acid	C18:1	$C_{18}H_{34}O_2$	141	11.3	1	4.04	1.01
Linoleic Acid	C18:2	$C_{18}H_{32}O_2$	143	11.4	2	4.12	2.06
Linolenic Acid	C18:3	$C_{18}H_{30}O_2$	145	11.5	3	4.21	3.16
Stearidonic Acid	C18:4	$C_{18}H_{28}O_2$	148	11.6	4	4.33	4.33
Arachidic Acid	C20:0	$C_{20}H_{40}O_2$	131	10.2	0	3.38	0.00
Gondoic Acid	C20:1	$C_{20}H_{38}O_2$	140	10.3	1	3.65	0.91
Eicosadienoic Acid	C20:2	$C_{20}H_{36}O_2$	144	10.4	2	3.76	1.88
Homo-γ-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.

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

1. PROJECT DESCRIPTION AND SCOPE

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

1.1 **Type of Biofuel Technology Proposed**

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

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

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

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

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

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

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

1.1.2 Inherent capabilities and limitations of HEFA technology.

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

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

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

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

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

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

1.1.3 Potential project hydrogen production technologies.

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

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

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

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[14] Karras, 2021b (Att. 3).

[15] *Id.* (median value from multiple Bay Area refinery steam reforming plants of 9.82 g CO_2/g H_2 produced)

[16] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model, appended hereto as Attachment 5.

[17] The naphtha reformers could supply additional hydrogen for project biorefining if repurposed to process petroleum gasoline feedstocks imported to ongoing refinery petroleum storage and transfer operations.

1.2 Process Chemistry and Reaction Conditions

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

1.2.1 <u>Key differences in processing compared with petroleum refining</u>

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

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

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

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

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

1.2.2 Relationships between feedstock choices, product targets and hydrogen inputs

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

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

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

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

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

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

1.2.3 Changes in process conditions of repurposed equipment

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

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

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

1.3 **Process Inputs**

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

1.3.1 Change and variability in feedstock chemistry and processing characteristics

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

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

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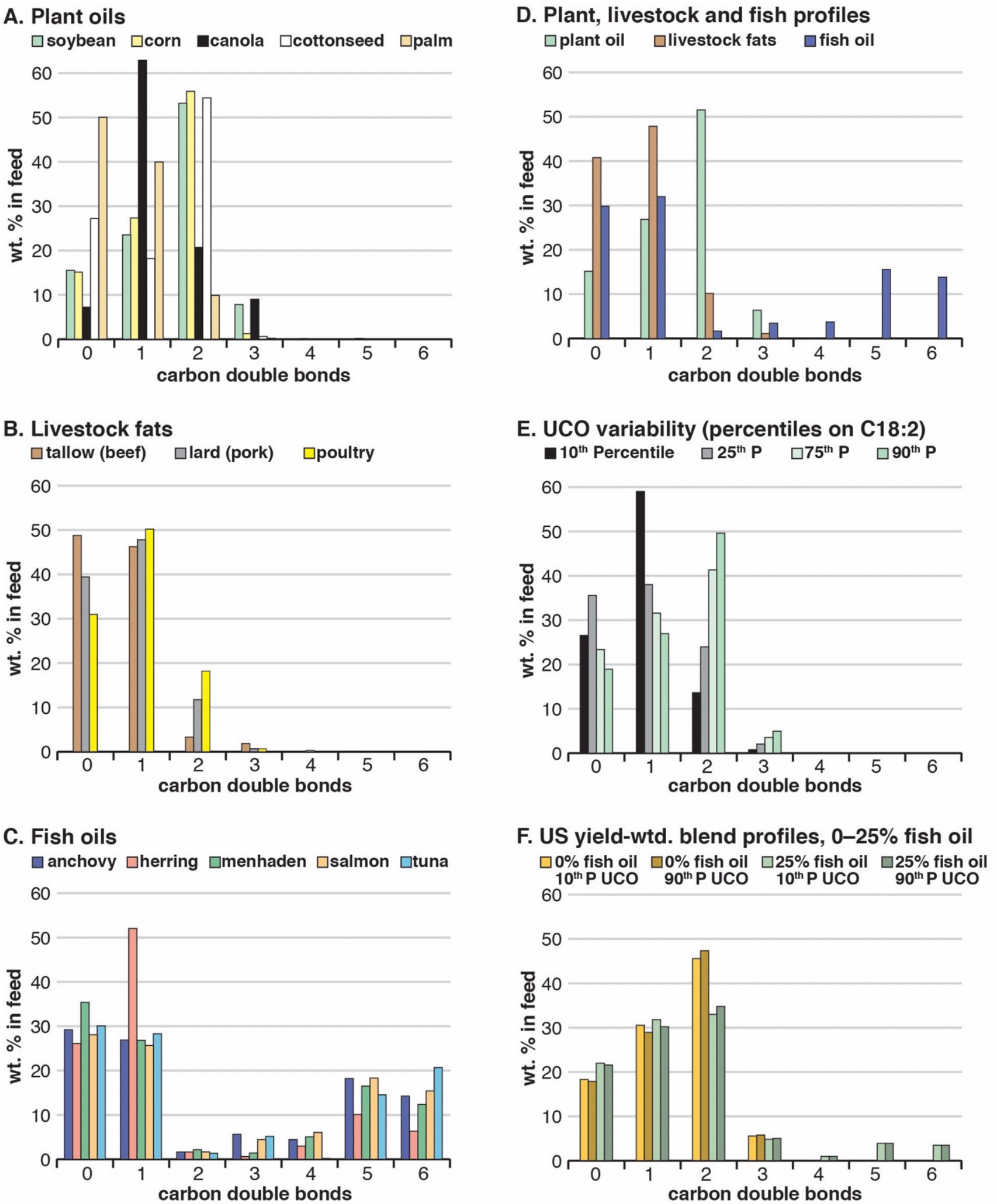
[38] See Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.

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

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

[41] See Krogh et al., 2015. *Crude Injustice on the Rails: Race and the disparate risk from oil trains in California;* Communities for a Better Environment and ForestEthics. June 2015. Appended hereto as Attachment 9.

[42] See Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).



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

1.3.2 Types and locations of potential project biomass feed extraction

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

1.4 **Project Scale**

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

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

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

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

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

MM t/y: million metric tons/year

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

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

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

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

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

[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 The Nustar Shore Terminals biofuel feedstock import conversion

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

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

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

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

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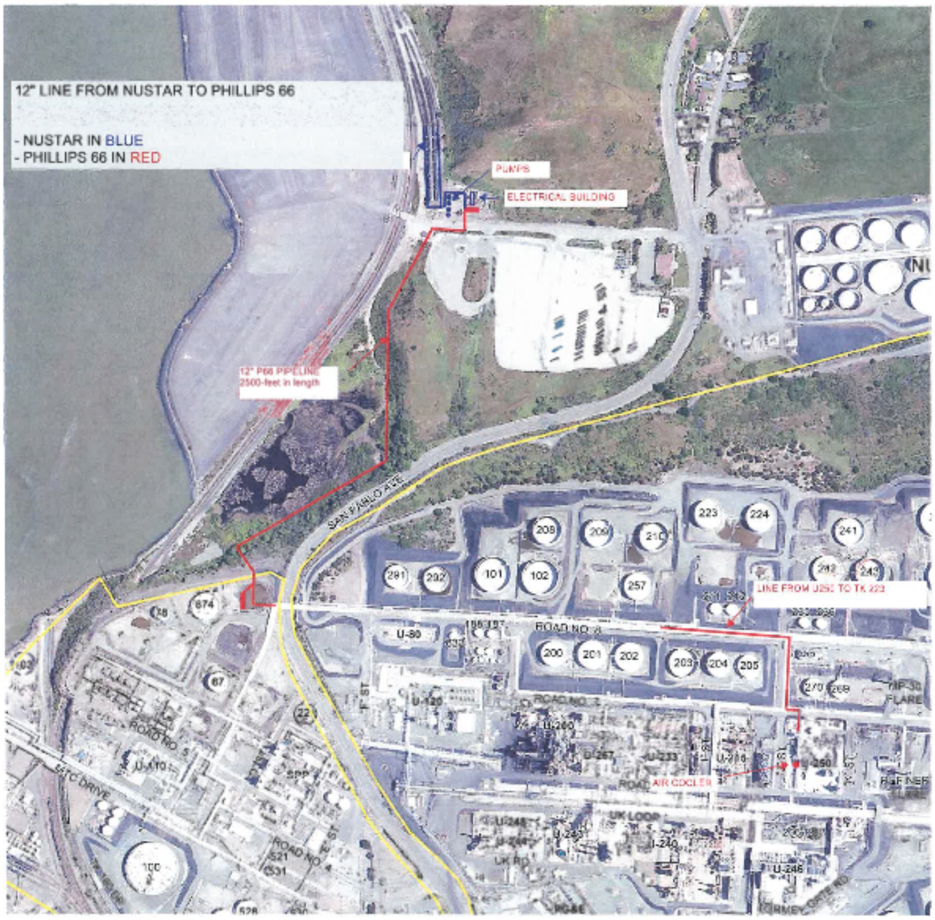
[59] BAAQMD, 2021 (Att. 14).
[60] Kupp, 2020a. Email text and attached site map from Gary Kupp, Contra Costa County, to Charles Davidson, incoming Rodeo-Hercules Fire Protection District director. 2 December 2020. Appended hereto as Attachment 15.
[61] *Id.*
[62] *Id.*



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

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

1.7.3 <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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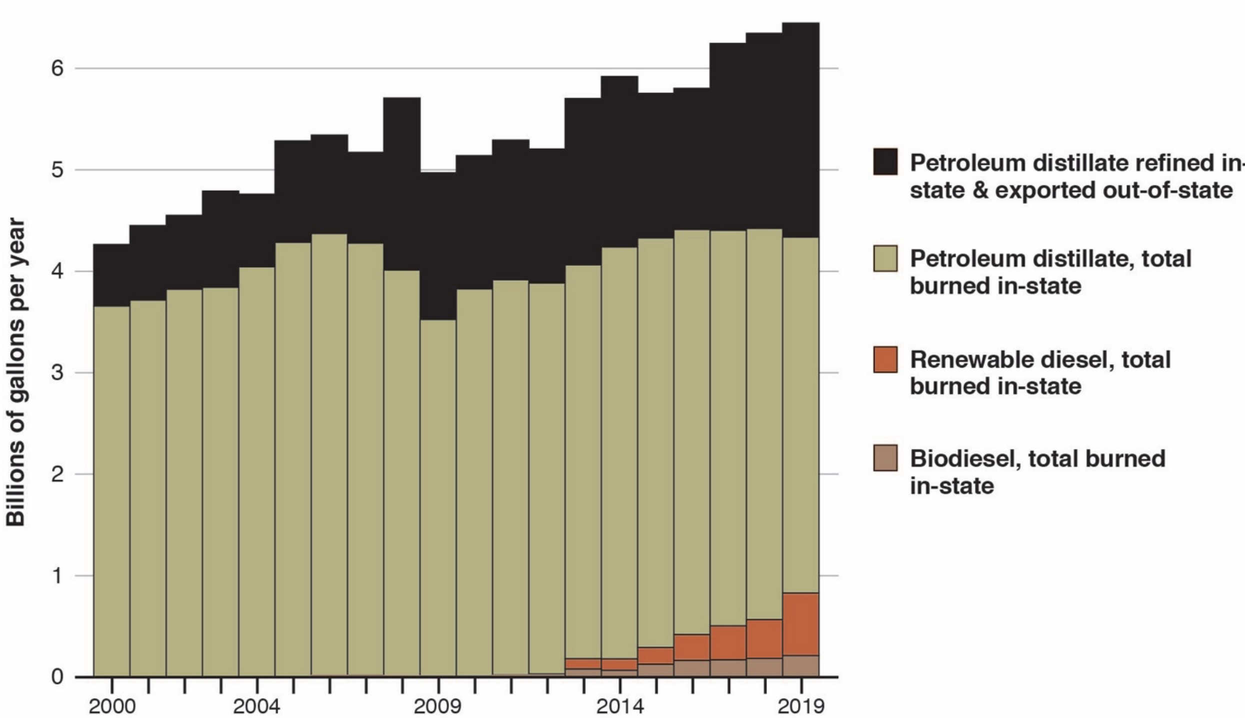
[74] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[75] "Project operations would decrease emissions of GHGs that could contribute to global climate change" (DEIR p. 2-5) including "indirect emissions" (DEIR p. 4.8-258) and "emissions from 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. *See* Chart 2 above. California refining capacity, especially, is overbuilt.[83] Industry reactions seeking to protect those otherwise stranded refining assets through increased refined fuels exports as domestic markets for petroleum fuels declined resulted in exporting fully 20% to 33% of statewide refinery production to other states and nations from 2013–2017.[84] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[85] *See* Table 2.

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

Total volumes reported for ten-year periods

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[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] <u>*See*</u> California refinery process safety management regulation, CCR § 5189.
[106] *Id.*
[107] *Id.*
[108] *Id.*
[109] DEIR p. 3-17.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[129] *Id.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.3 Uncertain Degree of Project Safety Oversight

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

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

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

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

4.1 The DEIR Did Not Evaluate Environmental Impacts of Project Flaring

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.1.1 <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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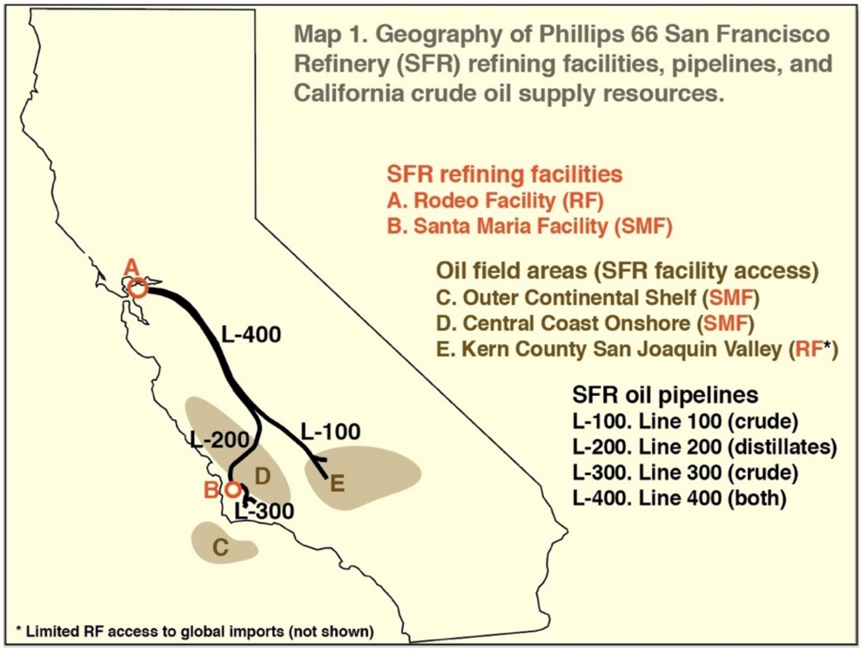
[155] The San Francisco Refining Complex (SFC) includes its Rodeo Refining Facility (RF), Santa Maria Refining Facility (SMF) and pipelines that feed crude to the SMF and crude blended with semi-refined oil to the RF.
[156] DEIR pp. 3-37 through 3-39; see also pp. 3-21, 5-12. Note that the DEIR picks 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

[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. <u>*See*</u> DOGGR, 2017. *2017 Report of California Oil and Gas Production Statistics;* California Department of Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. Appended hereto as Attachment 39.
[167] CEC, 2021a (Att. 38).
[168] DEIR p. 5-3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[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.

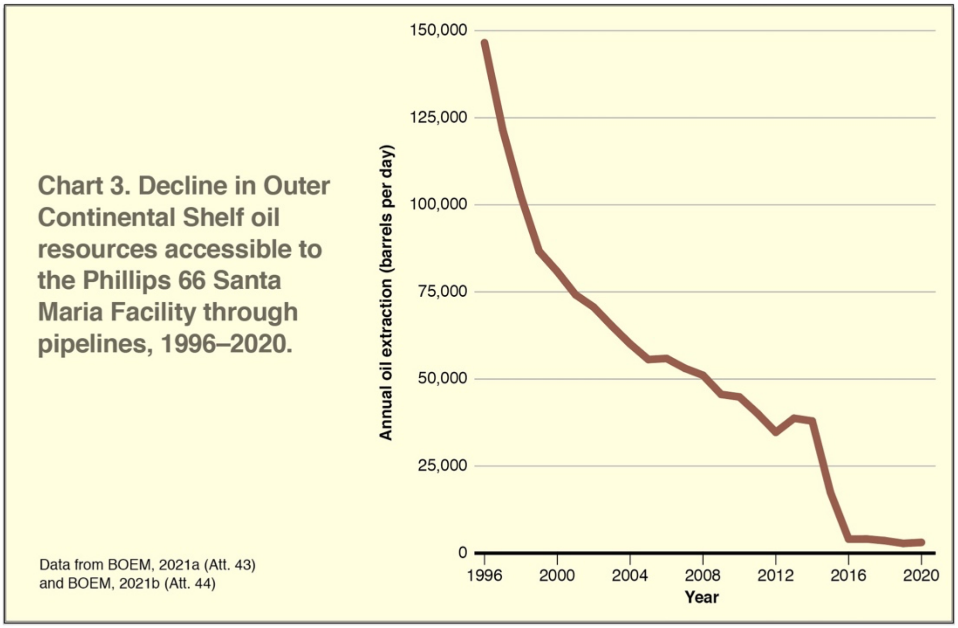

Chart 3. Decline in Outer Continental Shelf oil resources accessible to the Phillips 66 Santa Maria Facility through pipelines, 1996–2020.

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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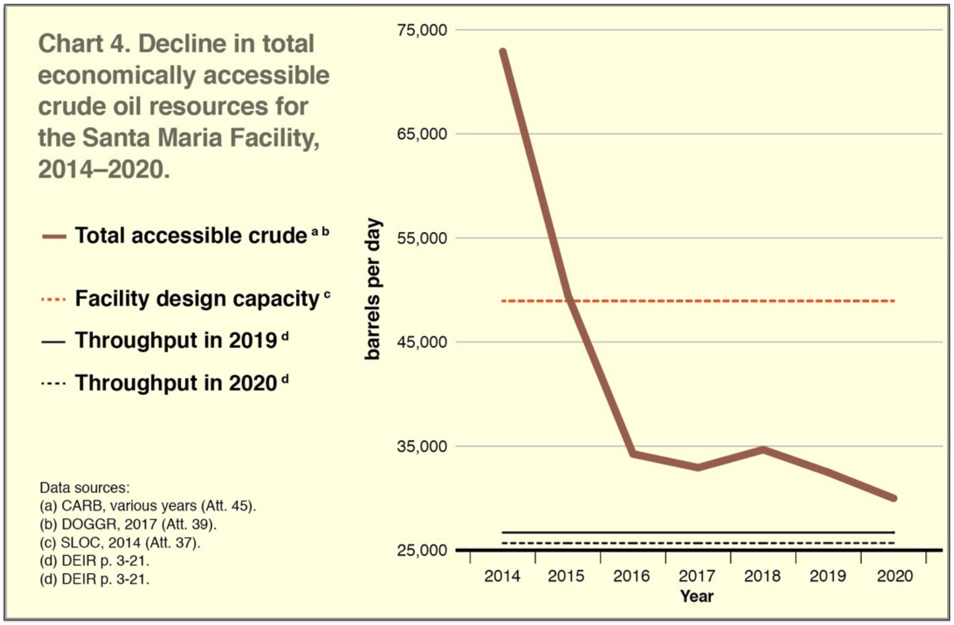
[181] These OCS oilfields that the SMF could historically or currently access via pipelines are the Point Pedernales, Point Arguello, Hondo, Pescado, and Sacate fields. <u>*See*</u> BOEM, 2021b (Att. 44).
[182] BOEM, 2021a (Att. 43).
[183] CARB, various years. *Calculation of Crude Average Carbon Intensity 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.

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

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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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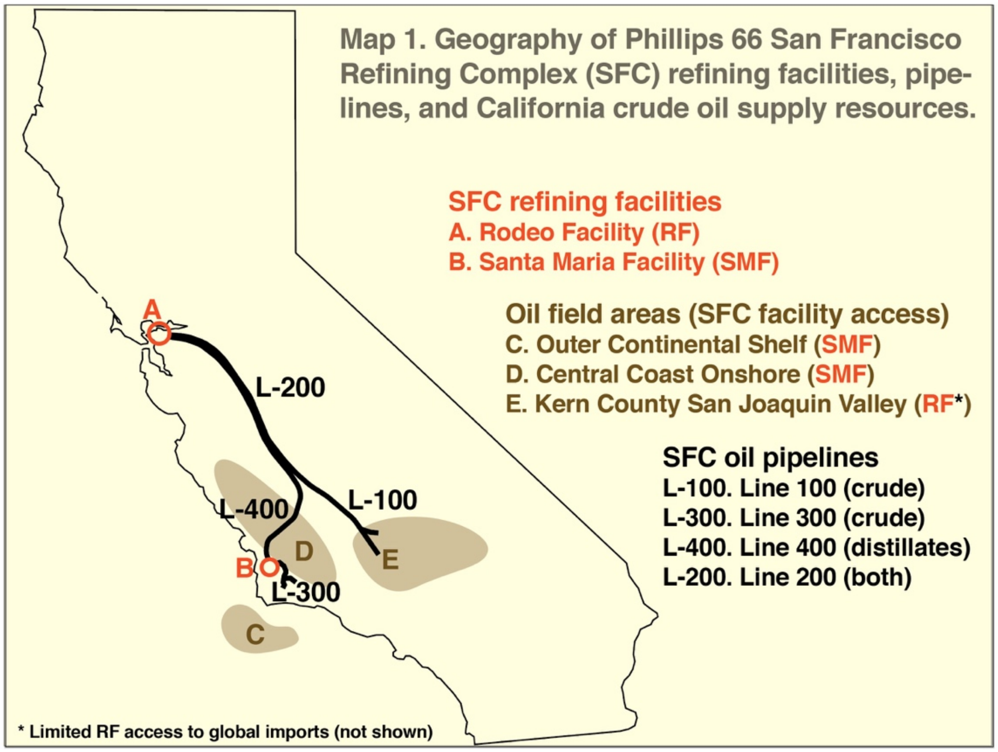
[1] Comment 36 Section III; Comment 36 Appendix C Section 5.
[2] FEIR at 3-328 to 3-338, 3-592, 3-593 (responses 50–64); 3-574 to 3-582, 3-623, 3-624 (responses C-46 to C-58); 3-3 to 3-15 (Master Response 1).
[3] FEIR at 3-3. *See* also FEIR at 3-13, 3-14.
[4] In particular, comment 36, Appendix C, Section 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.

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[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

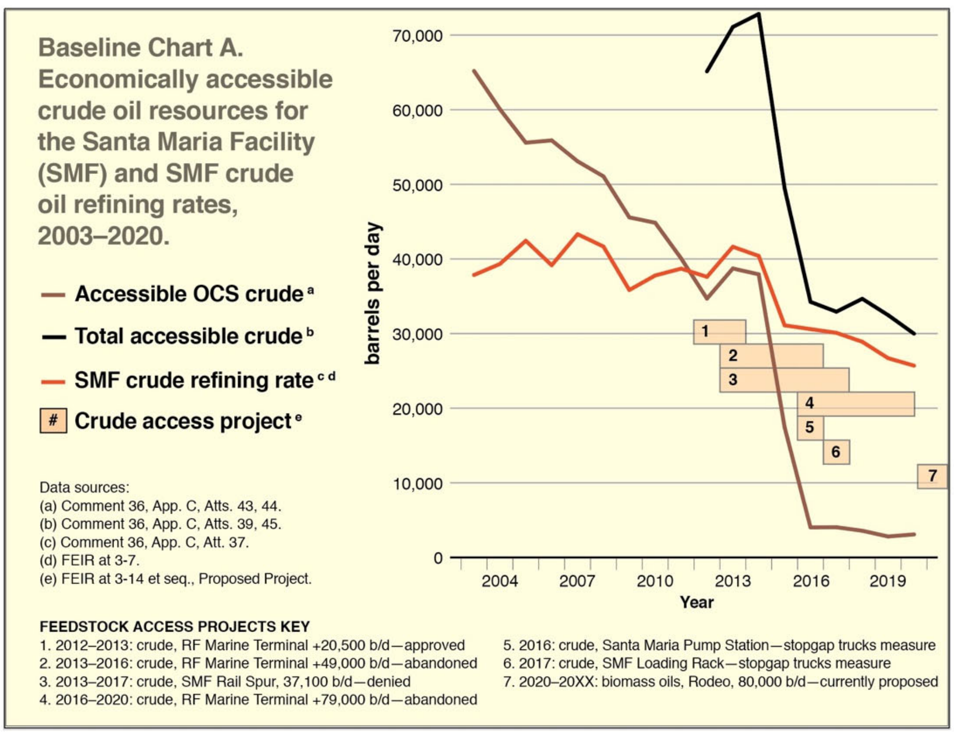
FEIR Master Response 1 states repeatedly that SMF crude rates have declined recently, and quantifies that decline from 2014 through 2020.[24]

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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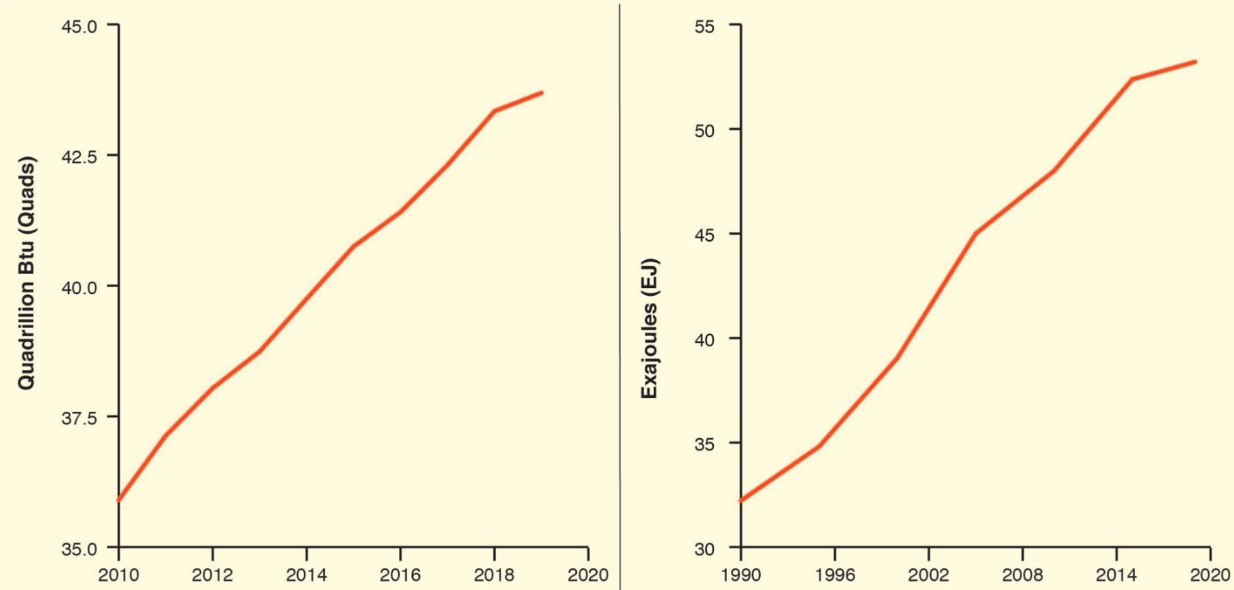
[1] Hydrotreated Esters and Fatty Acids (HEFA).
[2] Herein, GHG means carbon dioxide equivalents (CO_2e) at the 100-year climate forcing horizon.
[3] Comment 36, Appendix C, § 2; *see also* Comment 36 §§ VI.C.
[4] Responses to Comment 36 C-19 through C-23 and 112 through 115, FEIR at 3-620, 3-621 and 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

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[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 does not 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 instead of 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. *See* 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.

[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.

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[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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.	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.(	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.(	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.(	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.(	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.(	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.(	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.(	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.(	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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	0.5005	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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.:	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-IEO2021.4	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-IEO2021.5	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-IEO2021.6	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-IEO2021.7	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-IEO2021.8	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-IEO2021.9	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.4	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.5	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.6	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.7	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.8	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.9	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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-IEO2021.1	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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	Transportatic	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

Contents

Attachments

1.0 Flare Minimization Plan

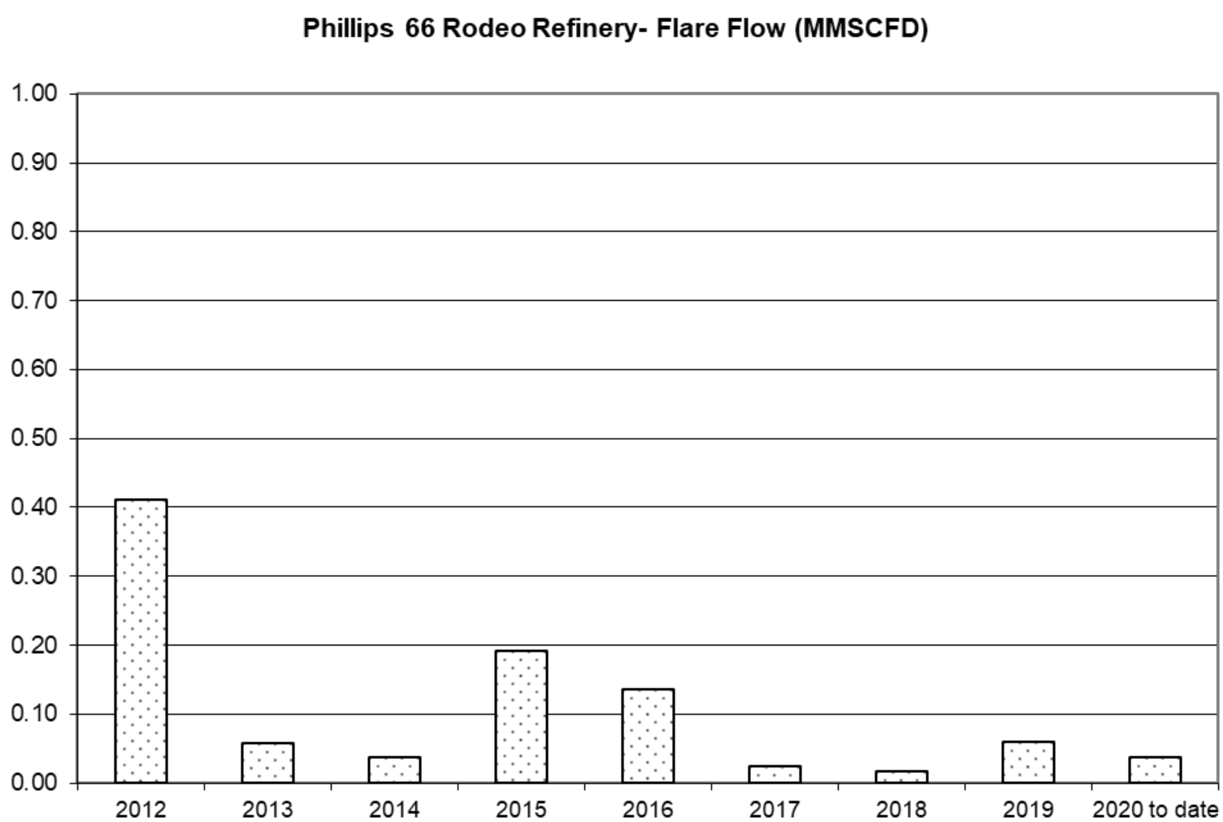
Regulation 12, Rule 12, was adopted by the BAAQMD in July, 2005, with the objective of reducing emissions from flares at petroleum refineries. This flare minimization plan for the Phillips 66, San Francisco Refinery (SFR) located in Rodeo, CA is consistent with progress toward that goal. It defines a 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.

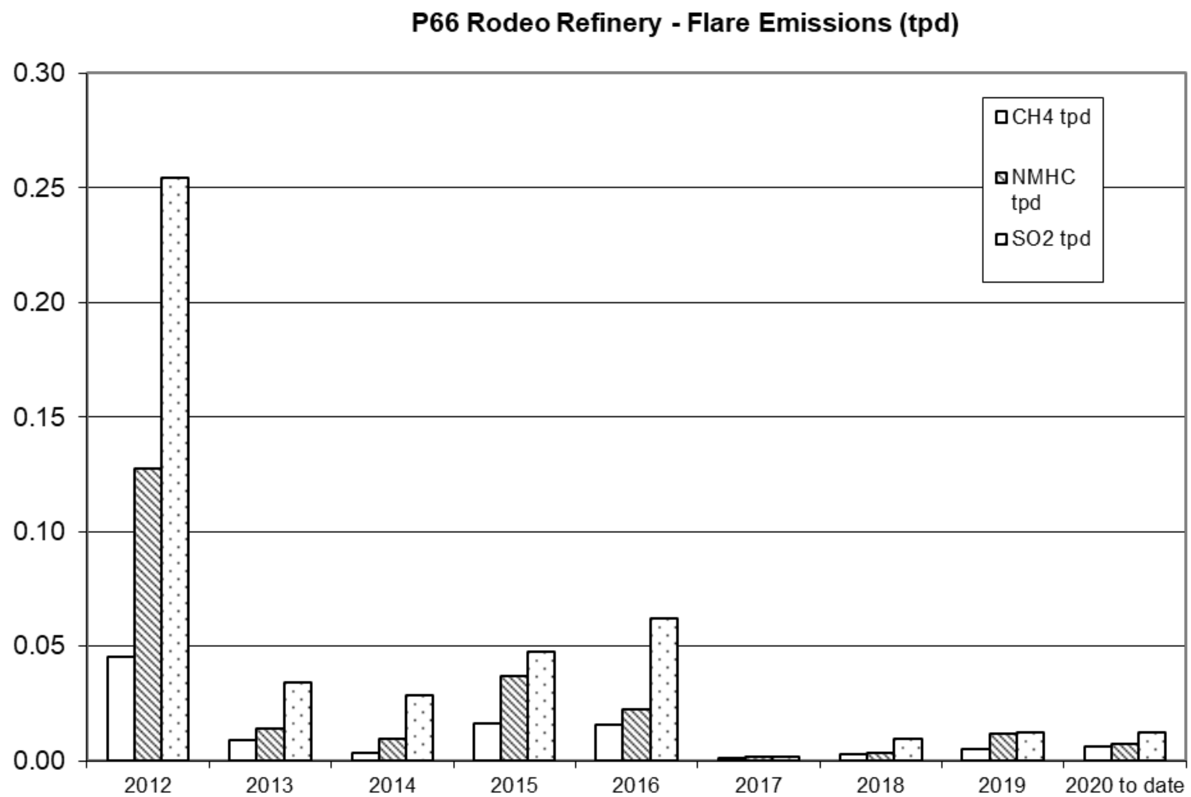
1.1 Safety Statement

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 ºF
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 ºF Shutdown - 350 ºF

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 Alarms: 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.

<table>
<tr><th colspan="2">Changes Made to Reduce Flare Emissions
(June 2012 – July 2019)</th></tr>
<tr><th>Year Installed or Implemented</th><th>Equipment Item Added, Process Changed or Procedure Implemented</th></tr>
<tr><td colspan="2">Procedures:</td></tr>
<tr><td>1st Qtr 2013 (updated)</td><td>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.</td></tr>
</table>

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***
Procedure:	
Equipment	
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)*	**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	4th 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.

<u>Fuel Gas Scrubbing</u>

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.

<u>Sulfur Recovery Units (U235, 236, & 238)</u>

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.

<u>General Measures (used at various units, as applicable)</u>

<u>Liquid Vessel Cleanup</u>

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.

<u>Depressurization</u>

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.

<u>Pressure Relief</u>

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.

<u>Source Reduction</u>

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

  - Fuel gas with low specific gravity (due to Hydrogen), or high heat of compression resulting in overheating
  - High inlet temperature to flare gas compressor
  - Monitored safety/protective parameter (e.g. vibration) triggered shutdown.
  - General mechanical problems inherent in the operation of rotating equipment.
  - High liquid level.
  - 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).

<u>Preventive Maintenance</u> - 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.

Turnaround Inspection And Repair - 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.

Critical Instruments & Safety Instrumented System

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.

Near Miss/Good Catch Program

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.

Solomon Refining Comparative Analysis

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

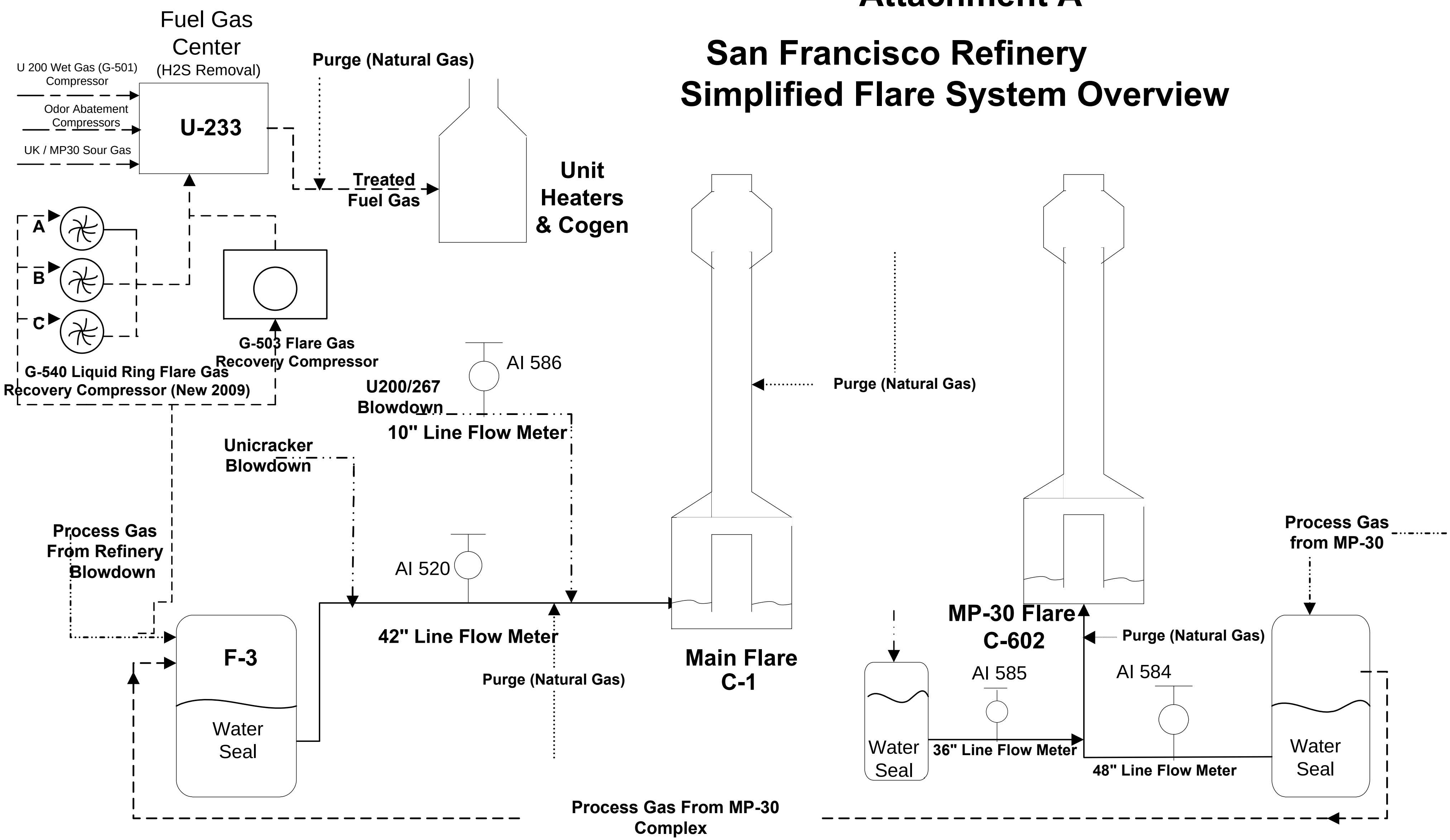
Flaring Incident Definitions	40 CFR 63.670(o)(3)
• Main Flare • MP30 Flare	• **> Smokeless Capacity**: The vent gas flow rate exceeds the smokeless capacity of the flare based on a 15-minute block average, and • **Visible Emissons** : Visible emissions are present from the flare for more than 5 minutes 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



J. Ahlskog, 07/2008

Flare System Overview...vsd

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.

<u>MP-30 Complex Blowdown Drum F-600</u>

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.

<u>Vacuum Protection for F-600 and F-604</u>

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.

<u>MP-30 Flare F-2 Blowdown Drum (Partial spare for F-1)</u>

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.

<u>MP-30 Flare Operation</u>

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.

Smokeless Flaring at MP-30 Flare

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.

Hot Coker Blowdown System

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.

F-502**-** 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

200:G-540A/B/C
FLARE GAS VAPOR RECOVERY COMPRESSORS
DESIGN: 954 SCFM @ 100 PSI ΔP
DRIVER: 600 HP/ 1180 RPM
SP. GR. @ °F
LIQUID RING

200:F-540
SERVICE LIQUID SEPARATOR
SIZE: 72" O.D. x 20'-0" S/S
DESIGN: 150 PSIG @ 550° F
(FV @ 300° F)

200:F-509
LOW PRESSURE SEPARATOR
SIZE: 30" ID x 10'-0" S/S
DESIGN: 275/-15 PSIG @ 100° F
INSULATION: NONE

200:GG-503
VAPOR RECOVERY COMPRESSOR
DESIGN: 3300 SCFM @ 165 PSI ΔP
DRIVER: 1000 HP/ 16 RPM
SP. GR. @ °F

200:40F-6
BLOWDOWN ACCUMULATOR
DIAMETER (INCHES): 114 ID x 20'-0" T/T
DESIGN: 15 PSIG @ 900° F
INSULATION (INCHES): 3" PP

200:40D-7
BLOWDOWN DRUM
DIAMETER (INCHES): 144 ID x 32'-0" T/T
DESIGN: 15 PSIG @ 900° F
INSULATION (INCHES): 3" PP

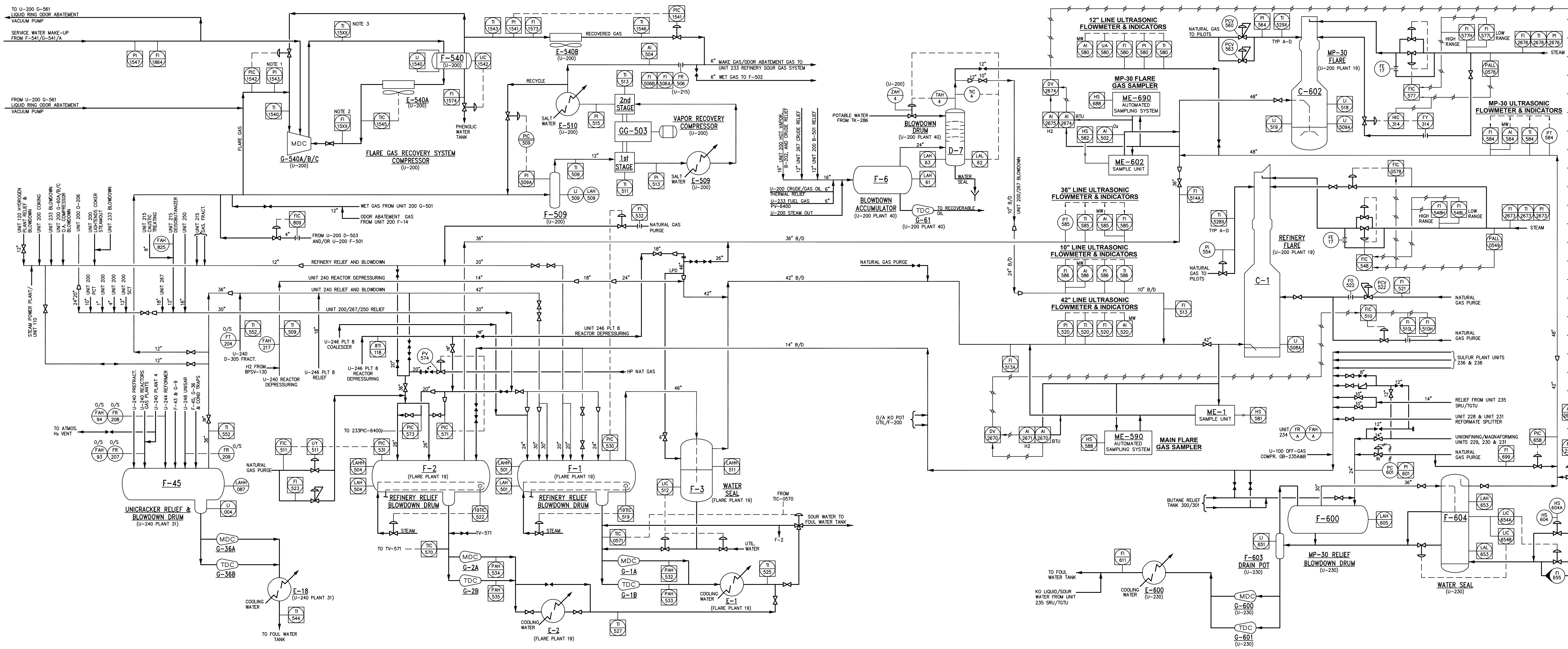
200:40G-61
BLOWDOWN DRUM PUMP-OUT
DESIGN: GPM @ PSI ΔP
DRIVER: HP/ RPM
SP. GR. @ °F

200:19C-602
MP-30 ELEVATED FLARE

WATER SEAL DRUM	FLARESTACK
12'-0" OD x 25'-0"	4'-0" OD x 225' ABOVE GRADE
DESIGN: 15 PSIG @ 650° F	DESIGN: 15 PSIG @ 650° F
INSULATION: NONE	INSULATION: NONE

200:19C-1
REFINERY FLARE

WATER SEAL DRUM	FLARESTACK
17'-0" ID x 20'-0"	3'-6" ID x 250' ABOVE GRADE
DESIGN: 15 PSIG @ 500° F	DESIGN: 3 PSIG @ 500°/400° F
INSULATION: NONE	INSULATION: NONE



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
REV: 9/30/2020 8:18 PM
BY: LBENNETT

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

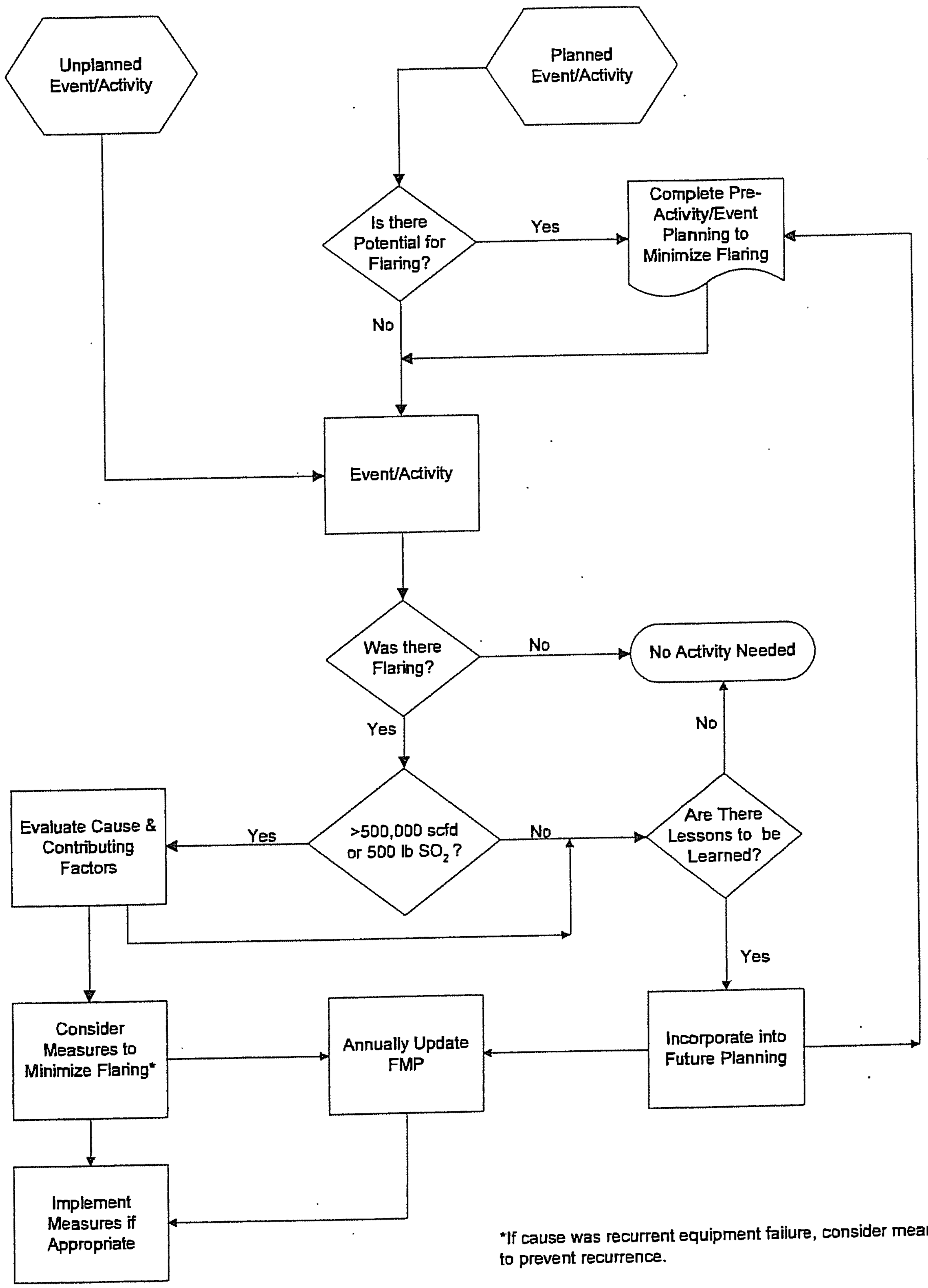
Unit Number	Unit Description
40	Raw Materials Receiving Unit
76	Gasoline Blending Unit
80	Refined Oil Shipping Unit
100	Process Water Unit
110	Hydrogen Plant
120	Hydrogen Plant (new in 2009, 3rd party operated by Air Liquide)
200	Coking Unit
200	Relief and Blowdown System
215	Gasoline Fractionation and 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

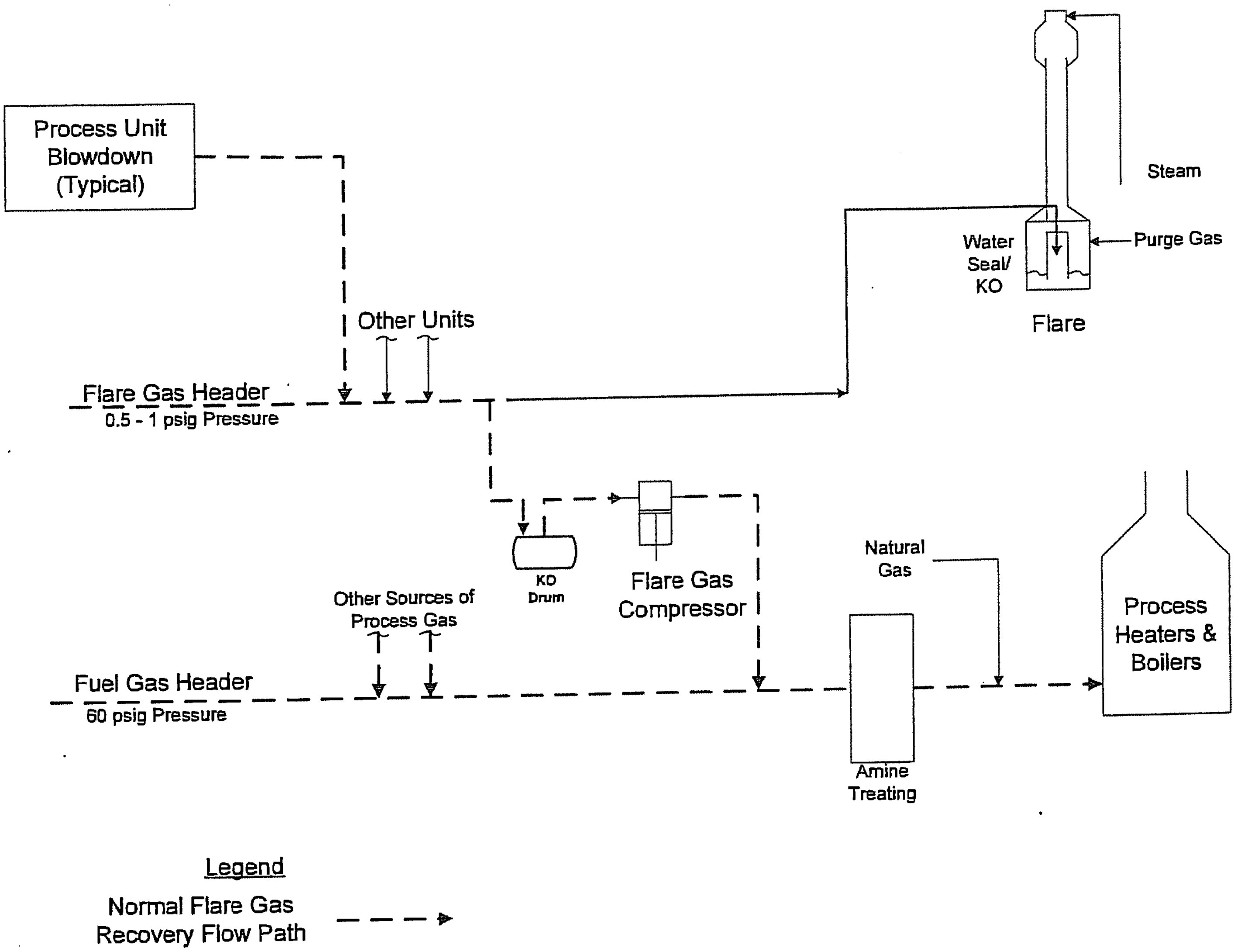


*If cause was recurrent equipment failure, consider means to prevent recurrence.

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

ESDR No. – Internal document tracking number.
Recurrent Failure – Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operating in a normal or usual manner. Recurrent is two times or more in a 5 year period. (BAAQMD 12-12-401.4.3)

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			

ESDR No. – Internal document tracking number.
Recurrent Failure – Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operating in a normal or usual manner. Recurrent is two times or more in a 5 year period. (BAAQMD 12-12-401.4.3)

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?
			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 SO_2 –202 lb (H_2S = 0.01 %) NMHC - 281 lb CH_4 – 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 SO_2 – 12,245lb (H_2S = 2.1 %) NMHC - 1,488 lb CH_4 –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

ESDR No. – Internal document tracking number.
Recurrent Failure – Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operating in a normal or usual manner. Recurrent is two times or more in a 5 year period. (BAAQMD 12-12-401.4.3)

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 SO2 – 975 lb (H2S = 0.04%) NMHC – 2272 lb CH4 – 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

ESDR No. – Internal document tracking number.
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Attachment H

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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 4[th], 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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Attachment H

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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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Attachment H

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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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Attachment H

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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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Attachment H

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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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Attachment H

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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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Attachment H

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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

ESDR No. – Internal document tracking number.
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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?
		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 - G-501 Compressor Shutdown Limit Enhancement	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. A suction pressure operating guideline will be incorporated into the Unit 200 start-up procedure to note the 15 psi limit (approximate).	COMPLETED 11/11/18 COMPLETED 4/16/19	Duration: 8.2 hours Flow: 1,182 MSCF Emissions (lb) SO_2 – 4,179 CH_4 – 445 NMHC – 591	• Upset/Malfunction – Loss of major compressor, G-501 Wet gas Compressor (4.2.1.4)	371-18 N
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) SO_2 – 2,075 CH_4 – 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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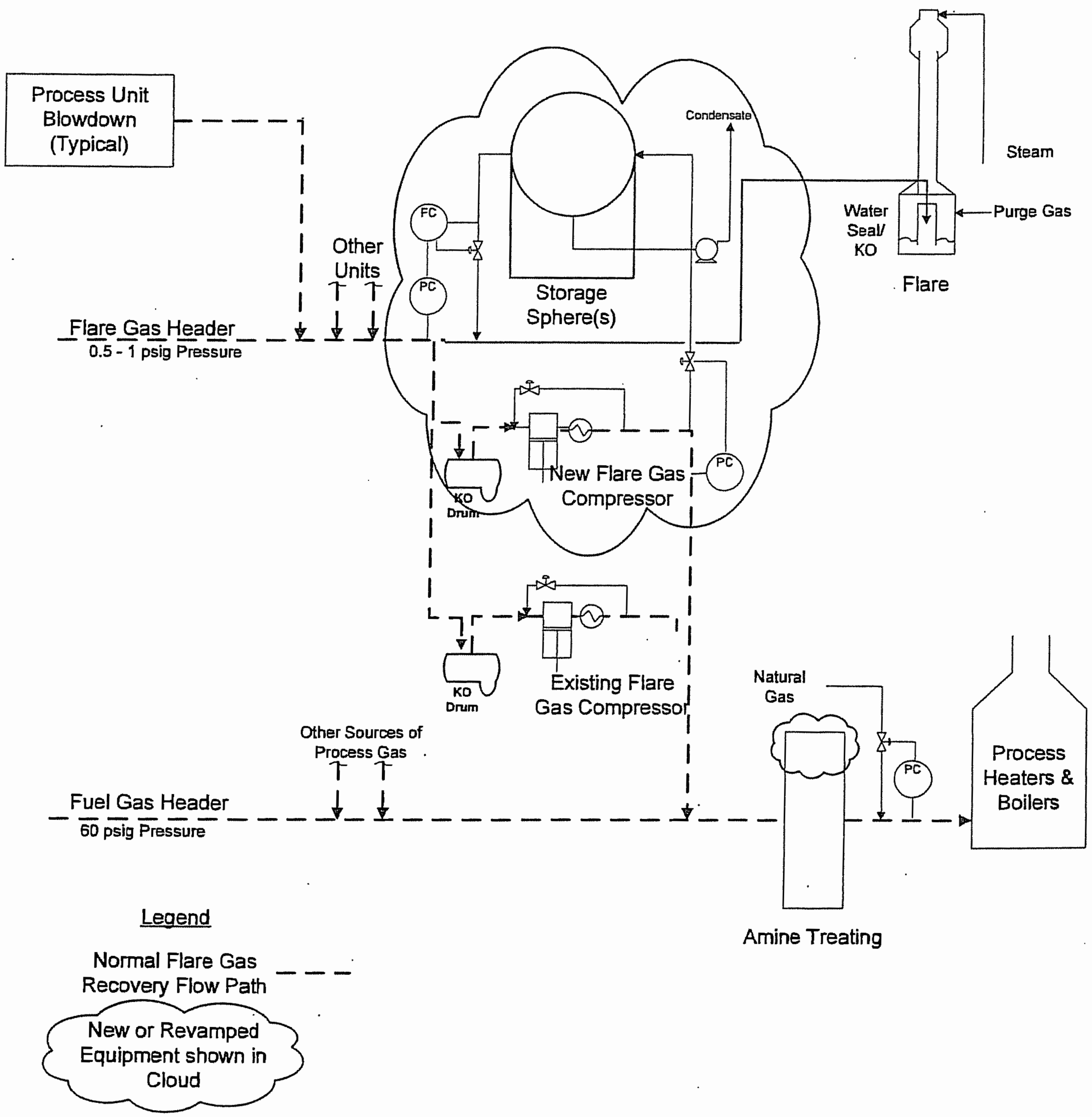
ATTACHMENT I

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

Attachment J

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 Effective	 5' 5'	 5.75' 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

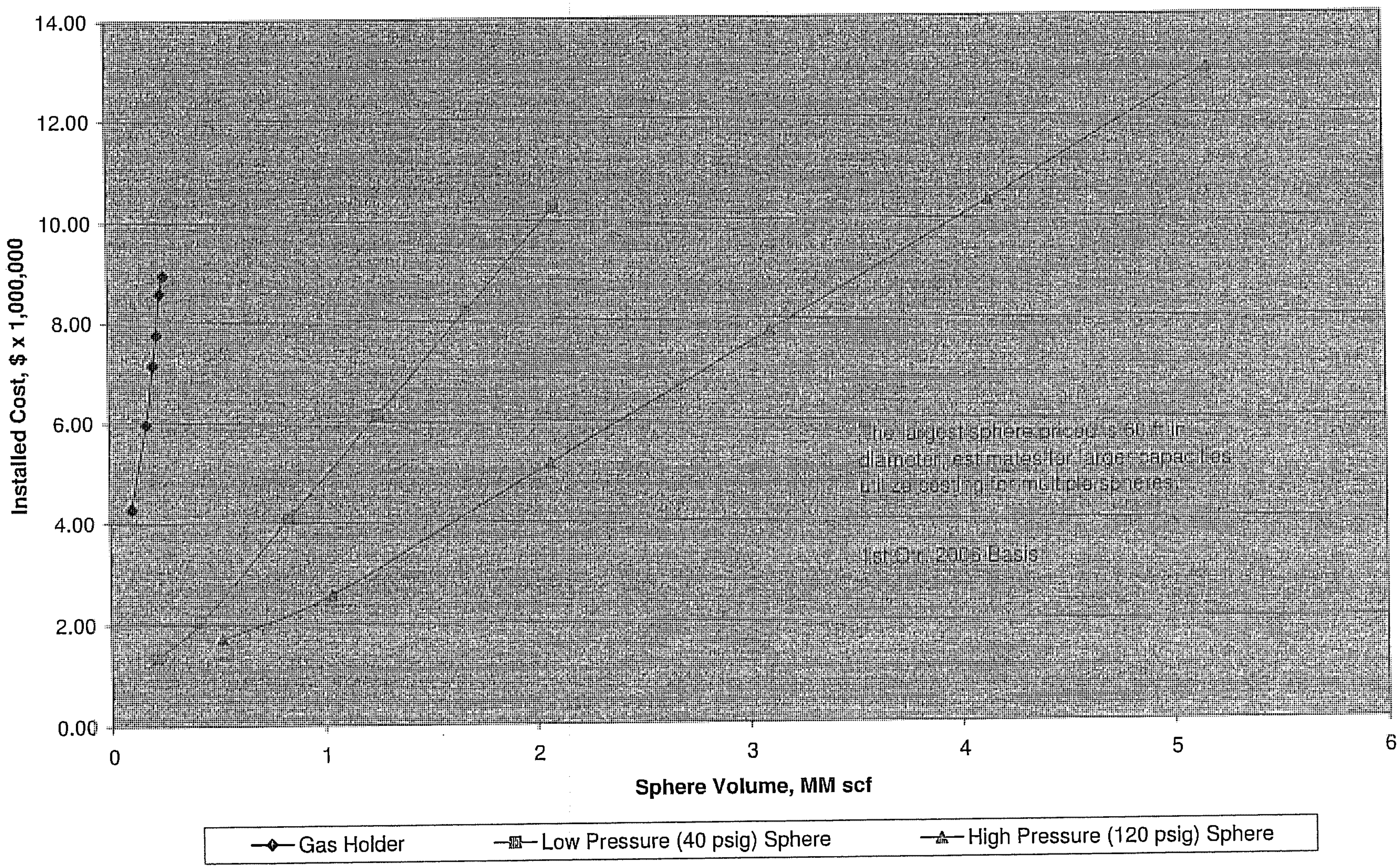
Cost Effectiveness Calculation Background Material

Attachment N

Cost Effectiveness Calculation Background Material

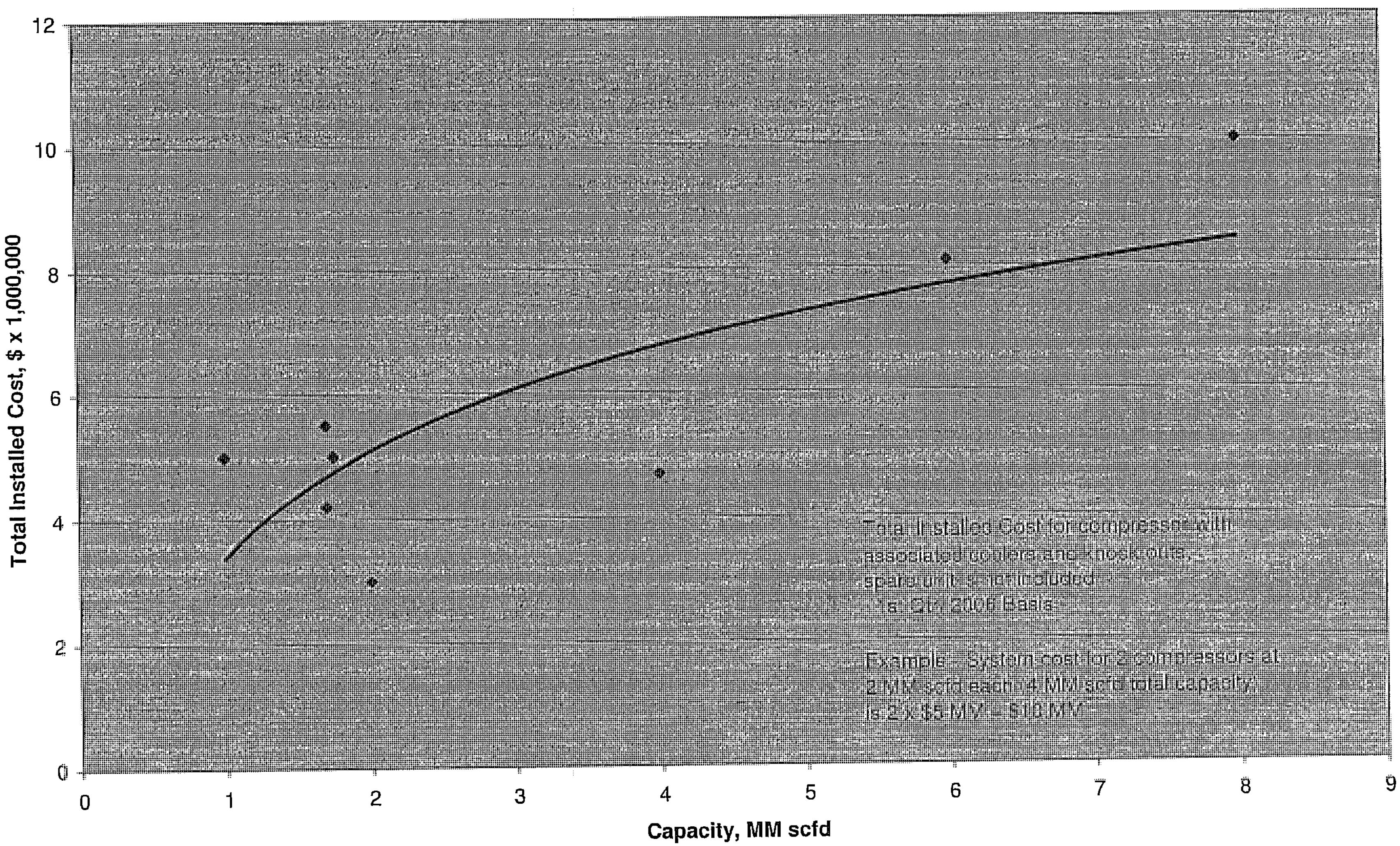
Cost Curves for Major Equipment

Flare Gas Storage Options

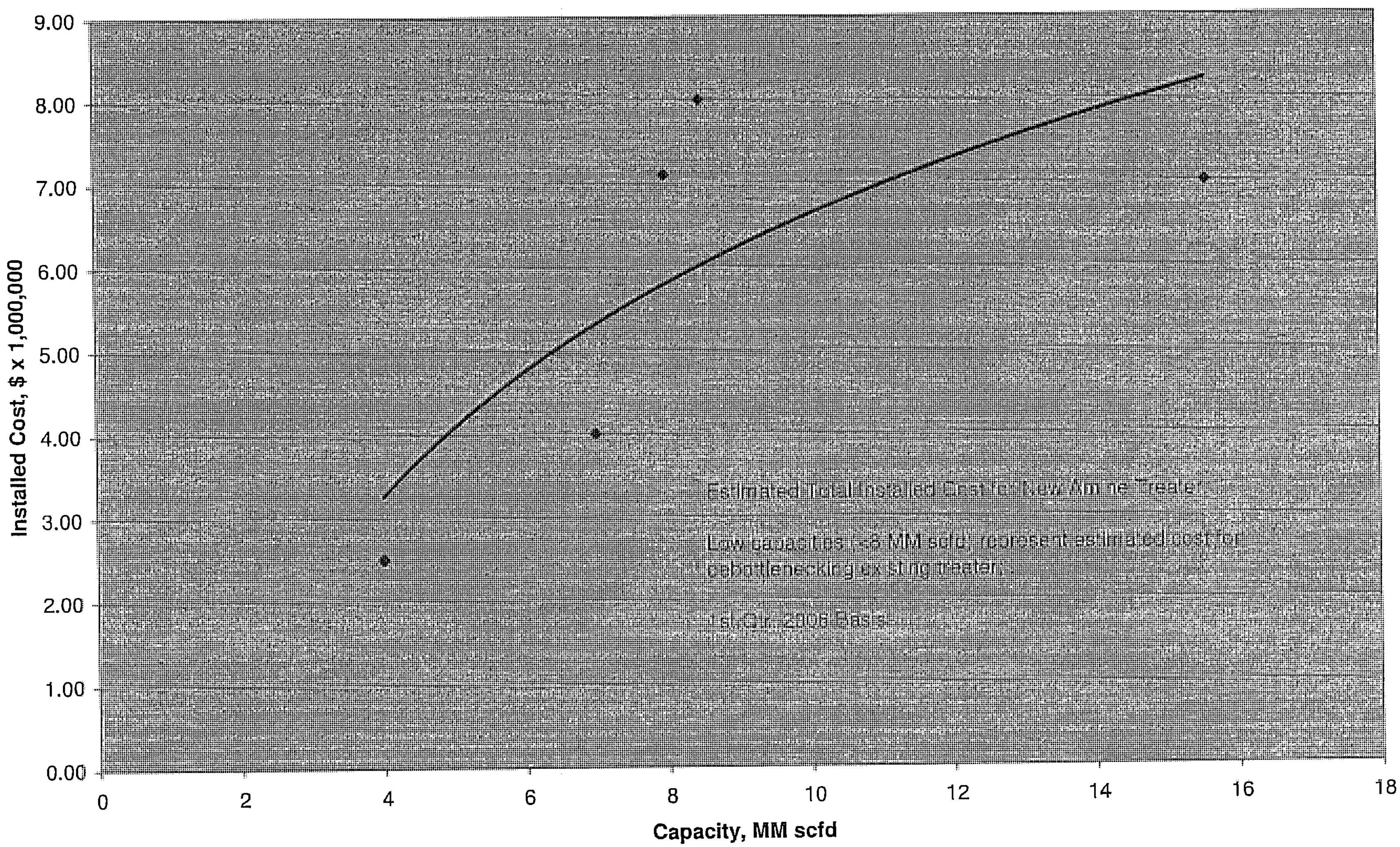


Confidential Attorney-Client Priviliged Work Document

Flare Gas Compressor System Costs



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)

Tom Sudol

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, & SO_2
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

	2005 Baseline Flaring		Proposed Flow to Control		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		0.003	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

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

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	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	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	Emission Evaluation: Controlled at Heater Emissions	Total Emissions	Emission Reduction
Control Method	Flare - Actual			Flare	Heater		
Total Volume to Flare (MMSCF/d)	0.25	0.034	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

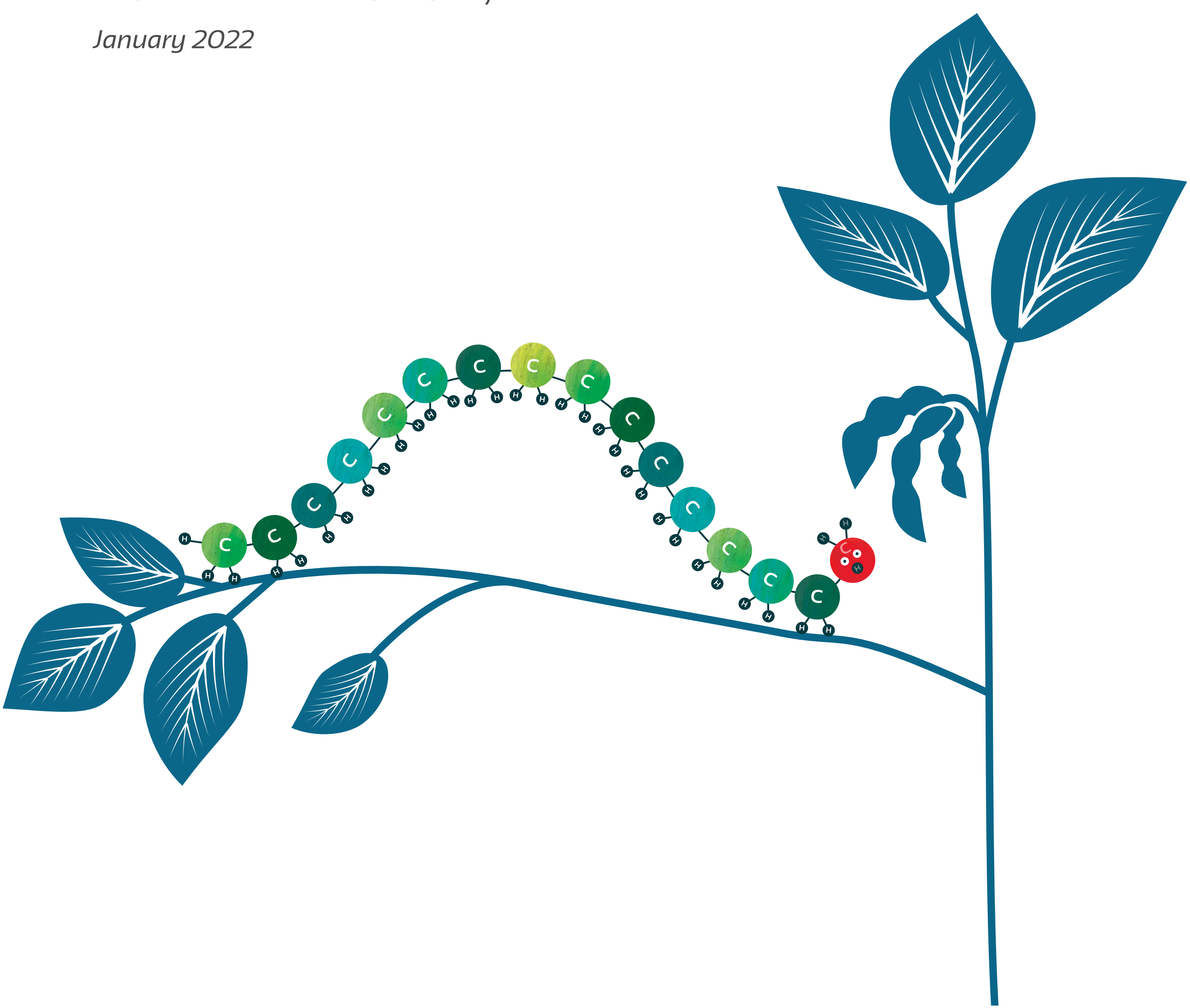
Cerulogy

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.

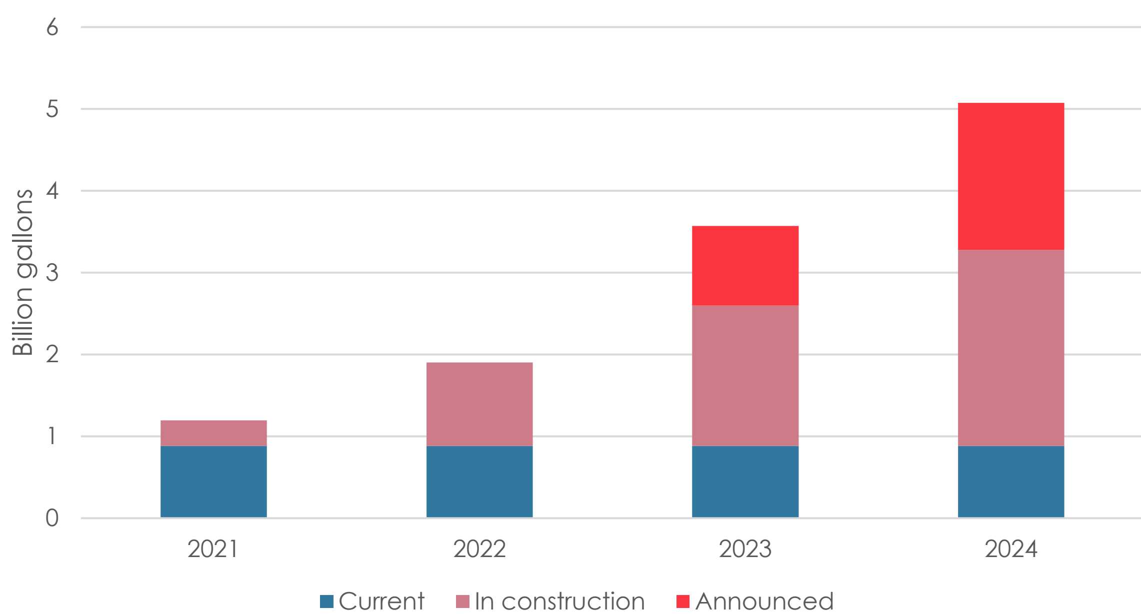

Figure 1. Announced renewable diesel production capacity expansion

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).

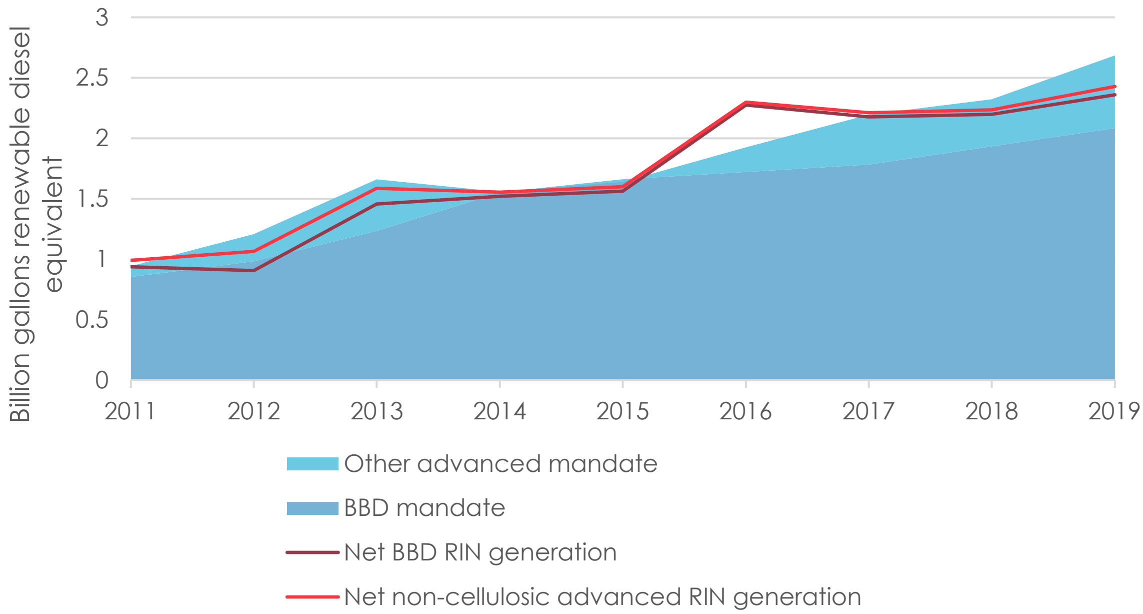

Figure 2. Renewable volume obligations and net* RIN generation for biomass-based diesel and for non-cellulosic non-biomass-based-diesel advanced fuels**

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.

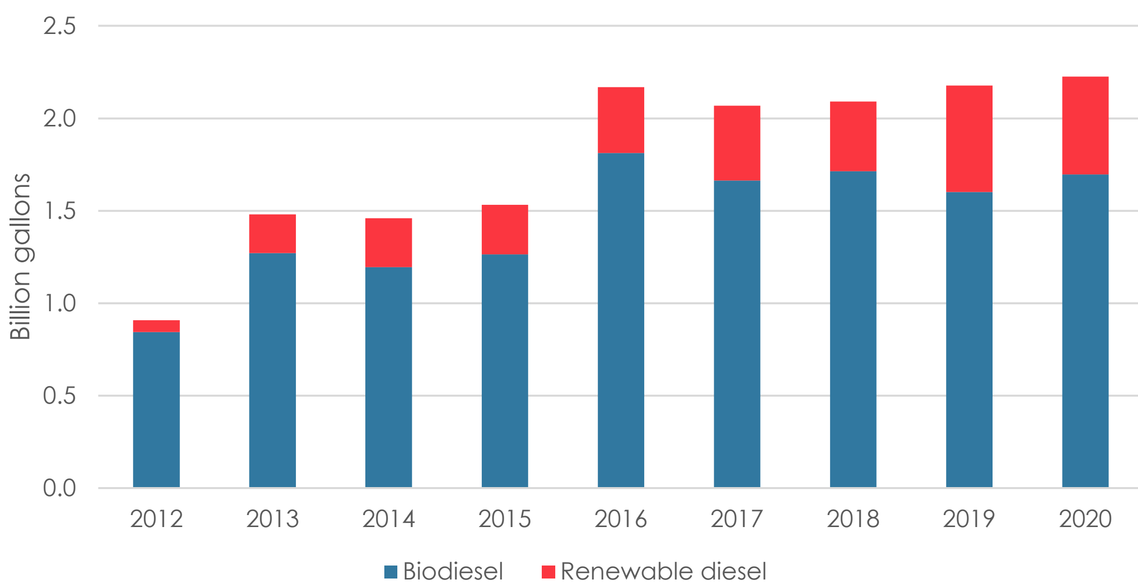

Figure 3. Supply of biodiesel and renewable diesel under the RFS (RDE)

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).

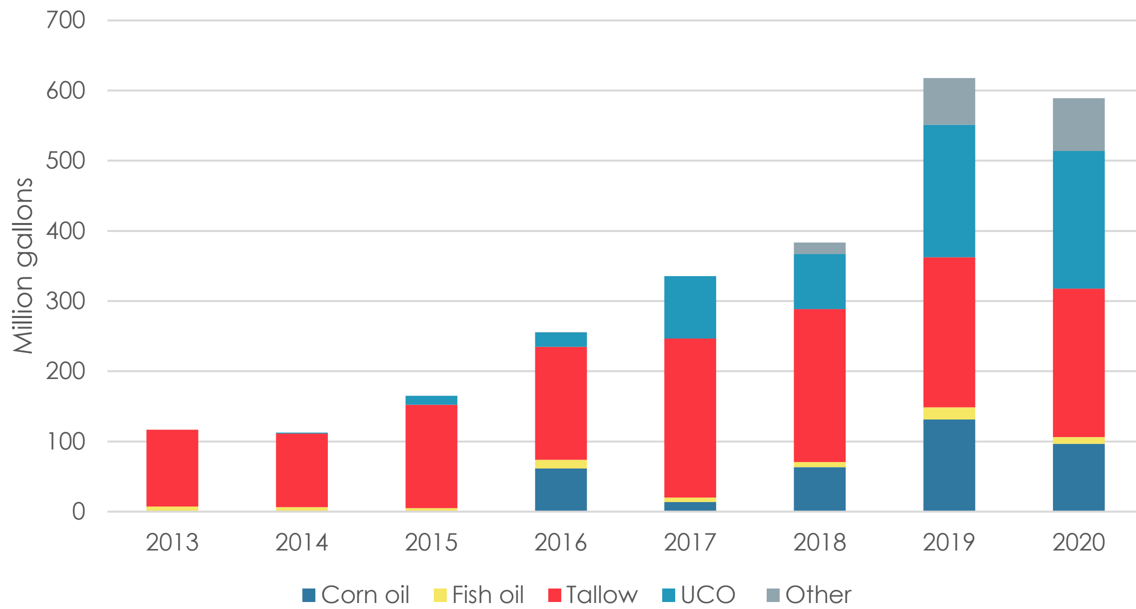

Figure 4. Renewable diesel supply by feedstock under the LCFS

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.

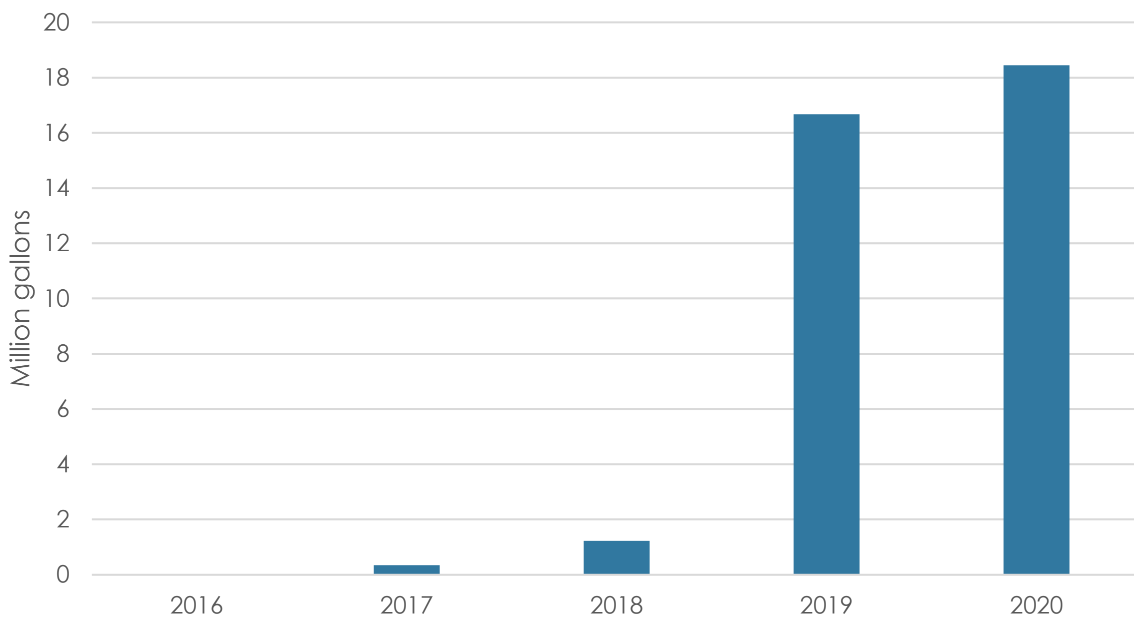

Figure 5. Renewable diesel consumption in Oregon

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.

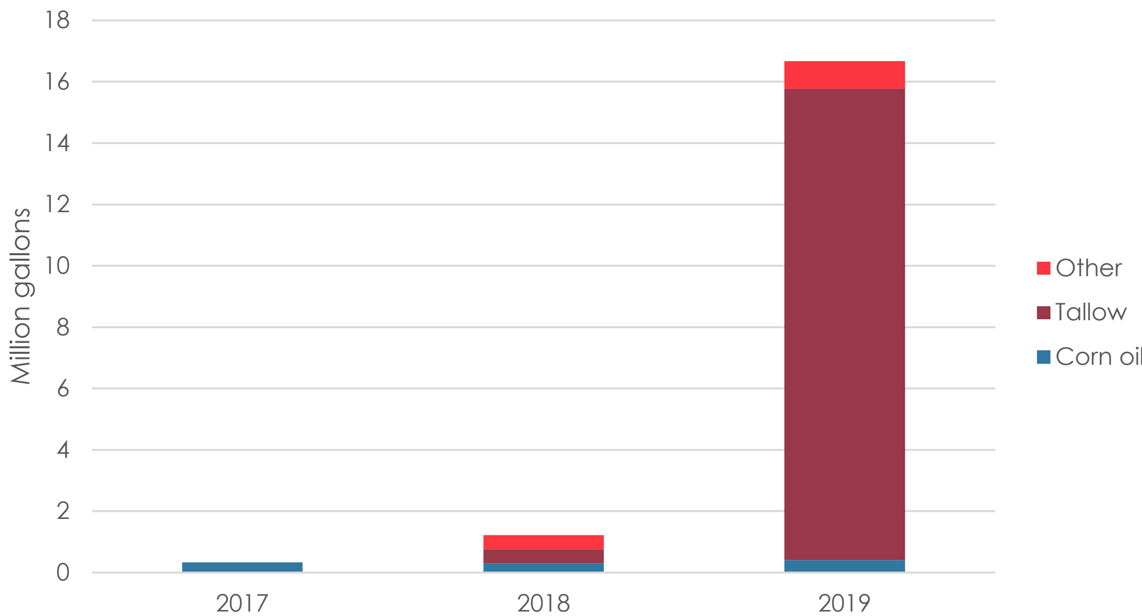

Figure 6. Feedstocks for renewable diesel supplied under the Oregon CFP

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.

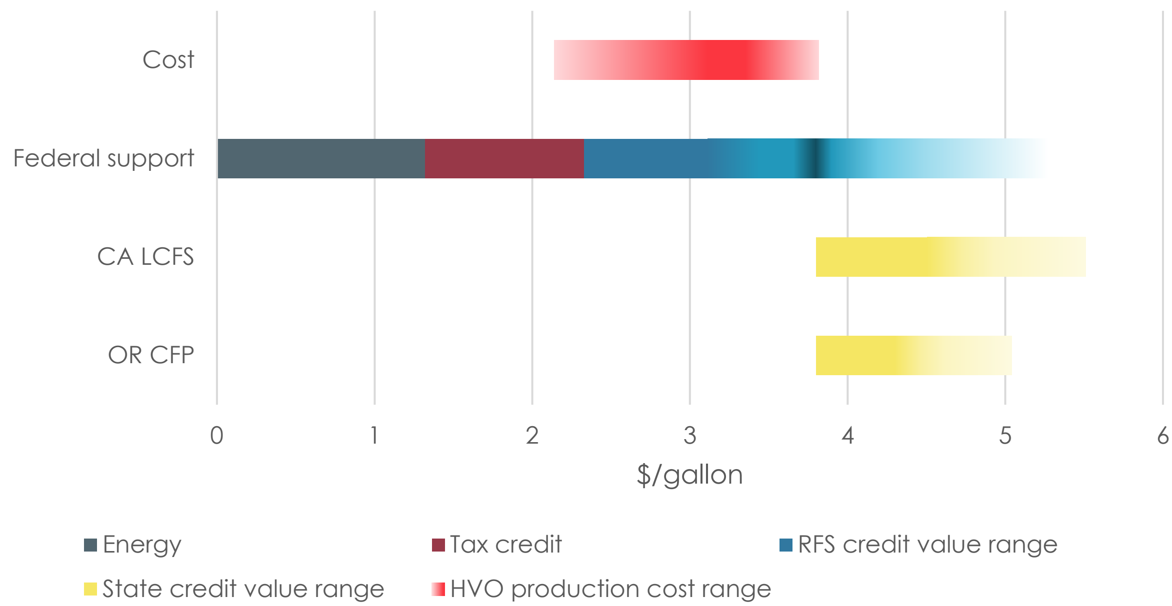

Figure 7. Indicative cost and value for renewable diesel sold into the California market

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

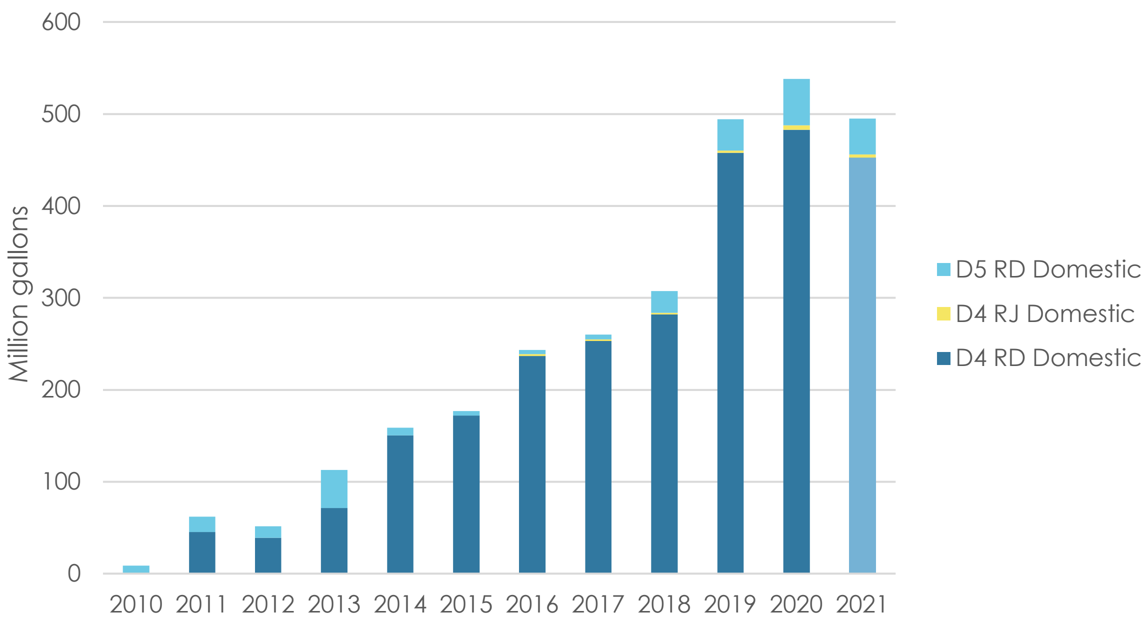

Figure 8. RIN generation by different classes of U.S. produced renewable diesel and jet fuel, 2010 to 2021*

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).

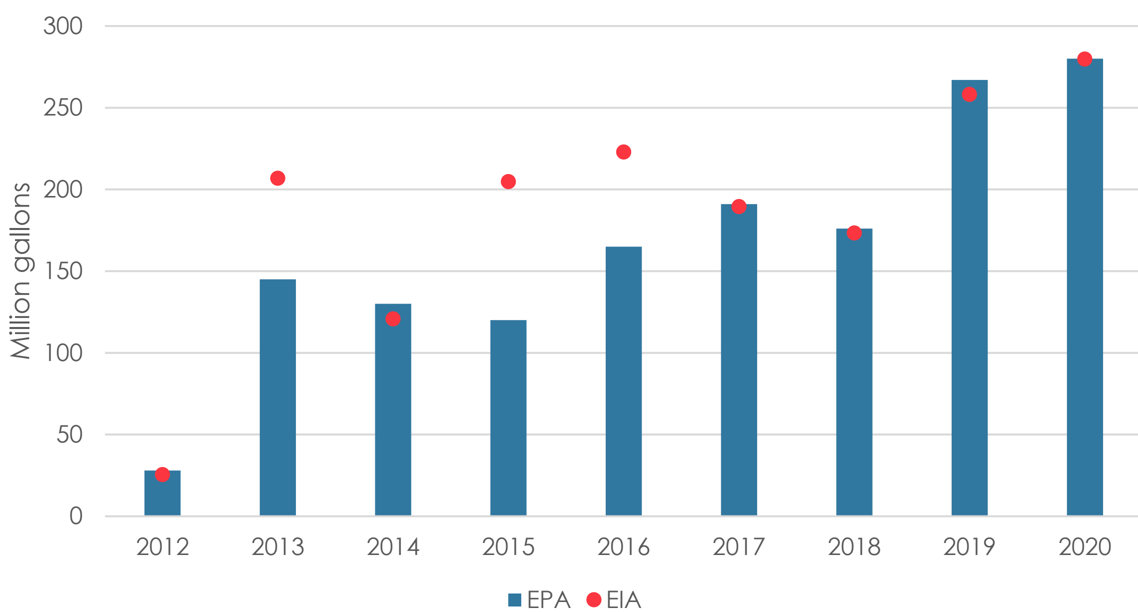

Figure 9. U.S. renewable diesel imports

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.

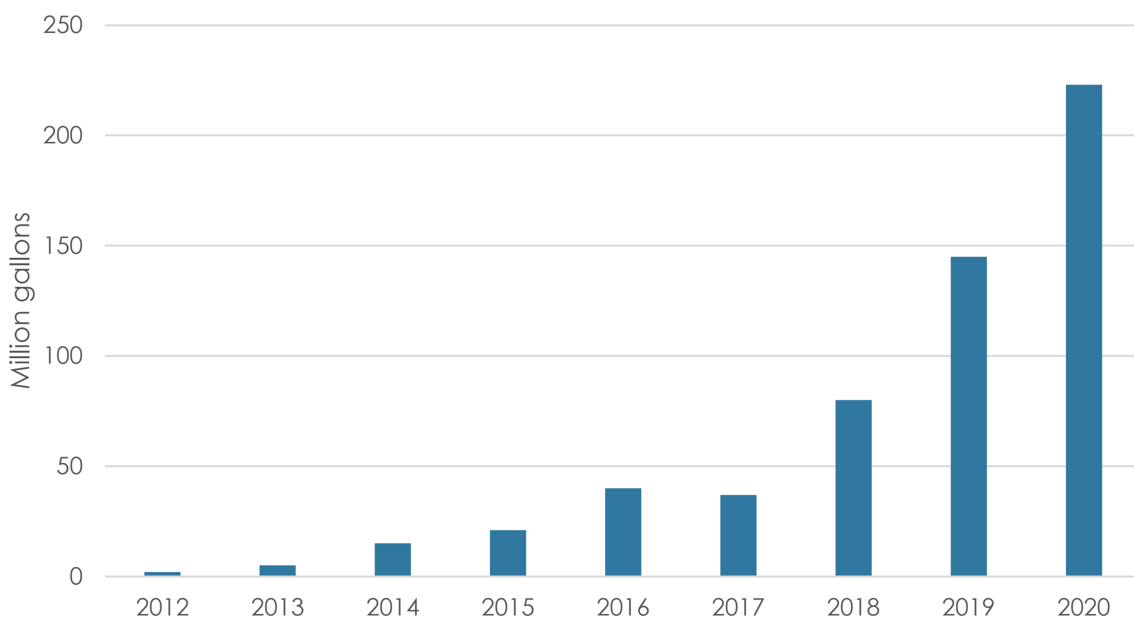

Figure 10. U.S. exports of renewable diesel

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.

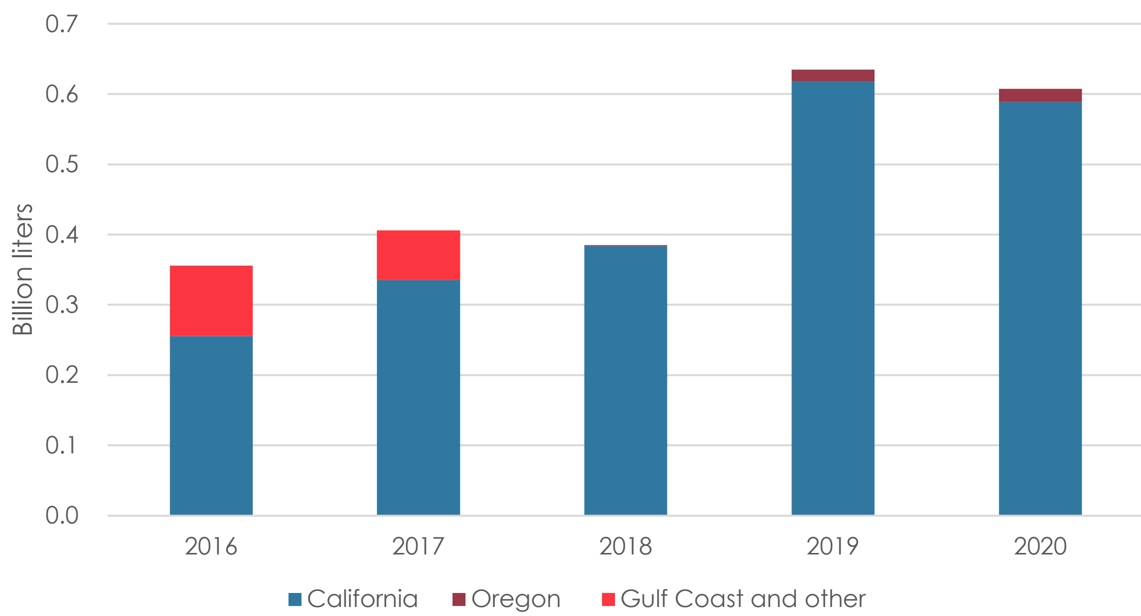

Figure 11. U.S. renewable diesel supply by region

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.

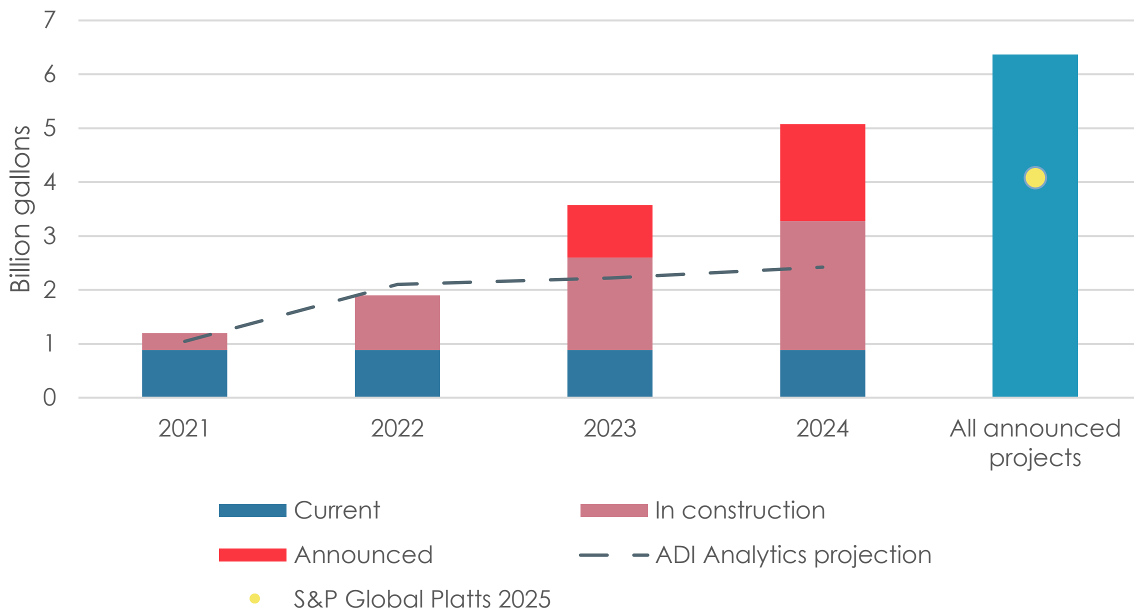

Figure 12. Potential growth in renewable diesel production capacity

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.

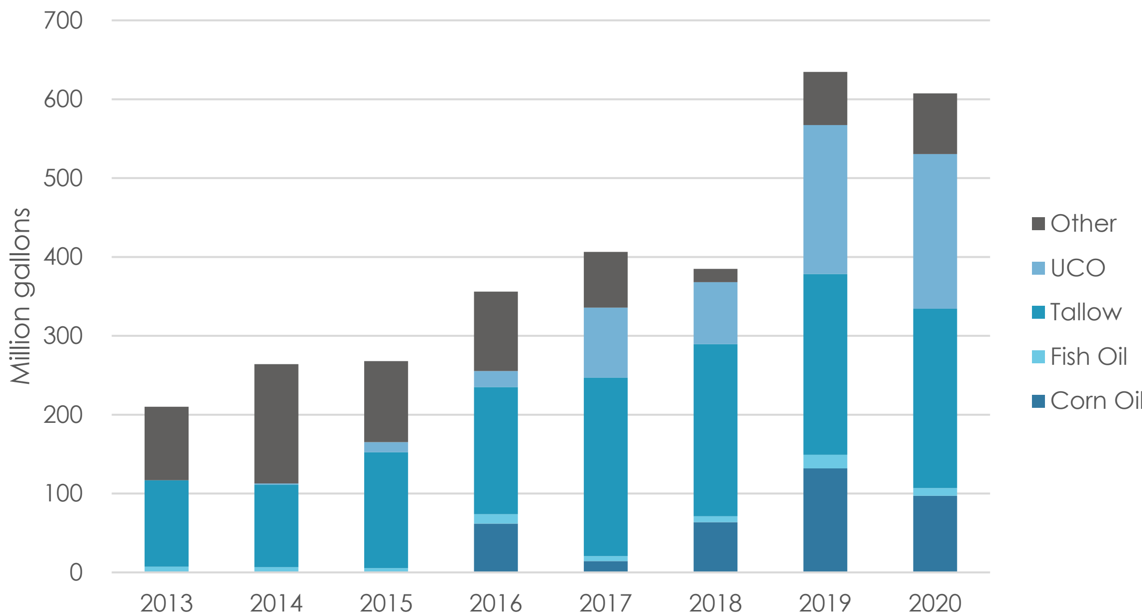

Figure 13. Estimated feedstock breakdown for renewable diesel supplied in the U.S.

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.

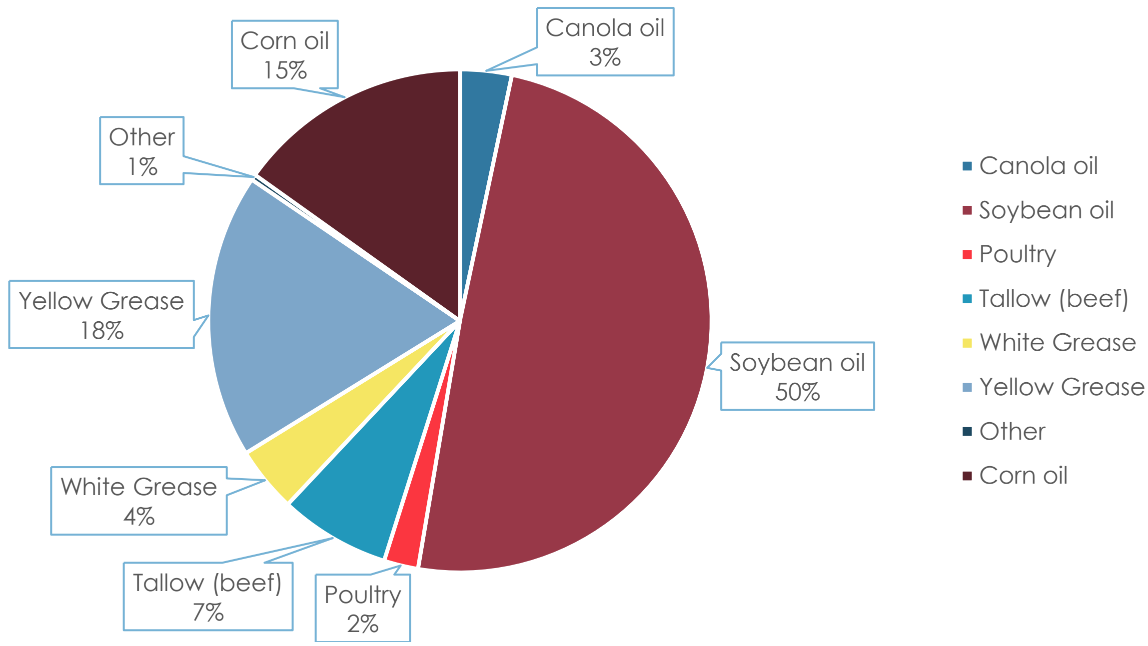

Figure 14. Feedstock mix for oil- and fat-based biofuels in the U.S., January to July 2021

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.

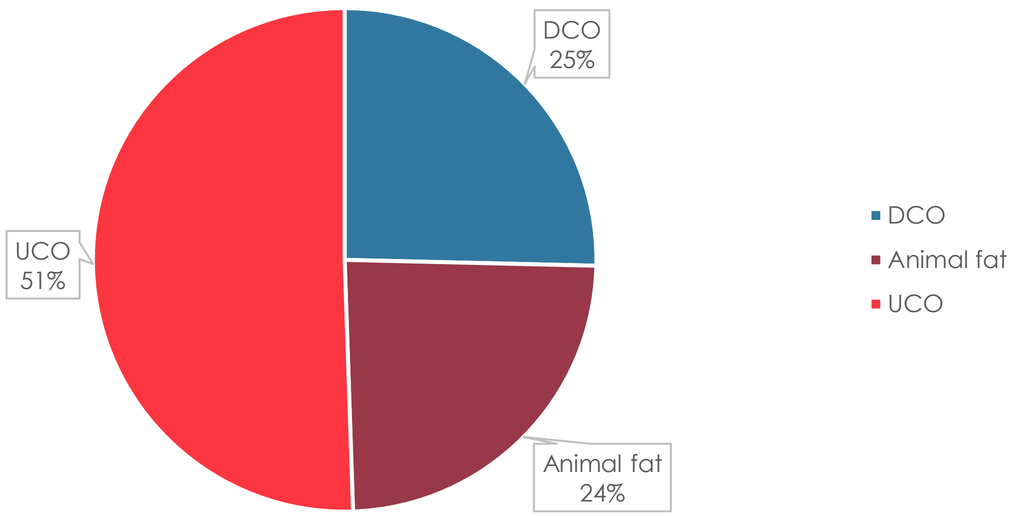

Figure 15. Renewable diesel feedstock mix implied by difference between EIA datasets

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.

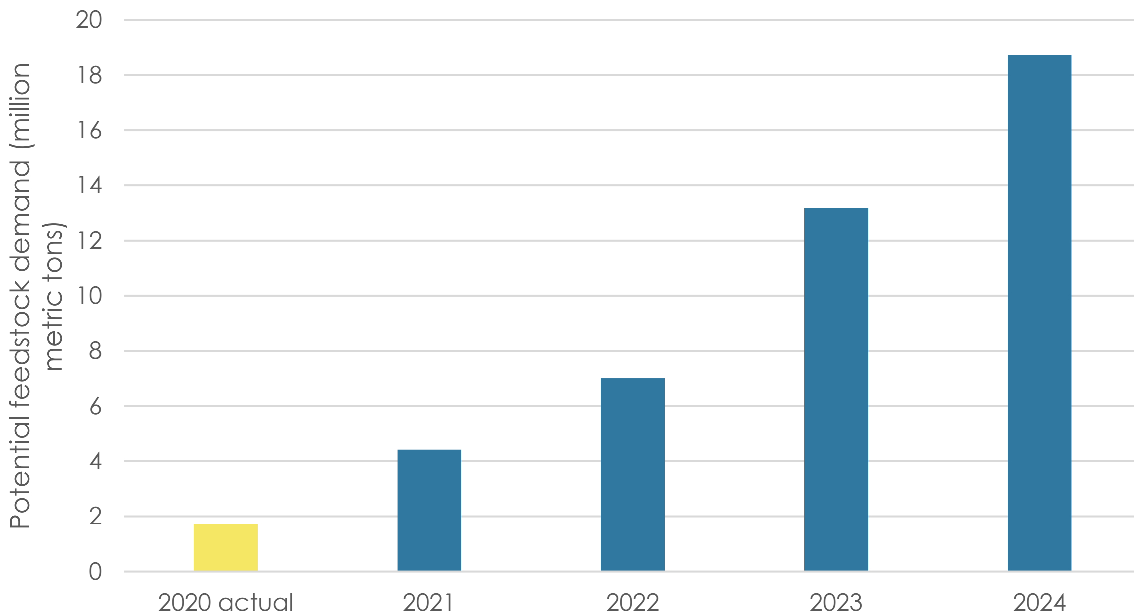

Figure 16. Potential feedstock demand for renewable diesel if all announced projects produced at 100% of capacity

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.

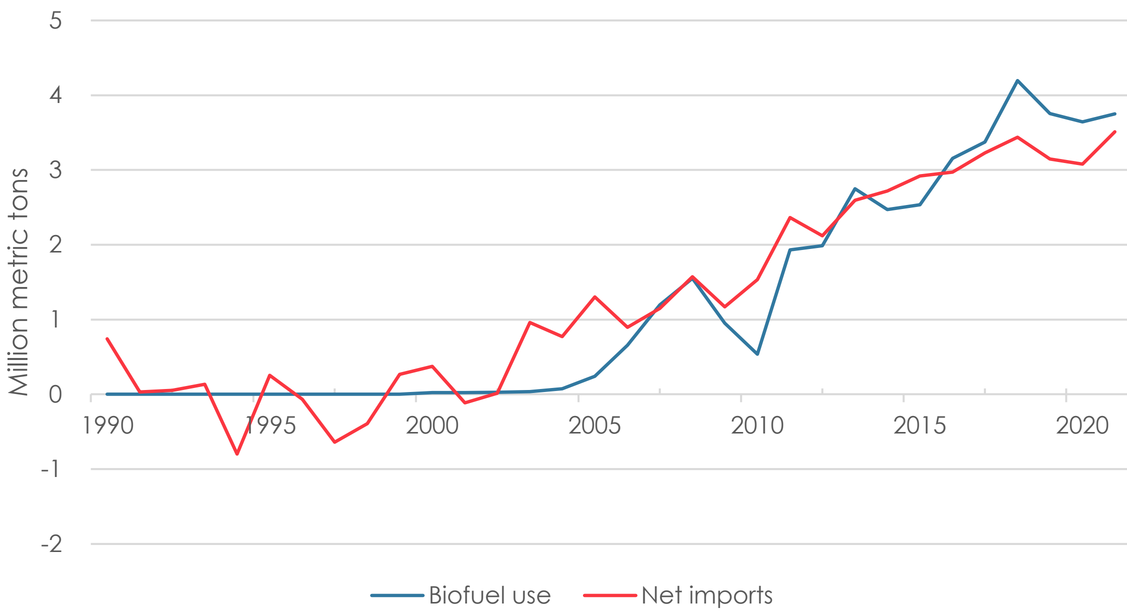

Figure 17. Increases in U.S. consumption of vegetable oils for biofuel production and in net vegetable oil imports, 1990 to 2021

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.

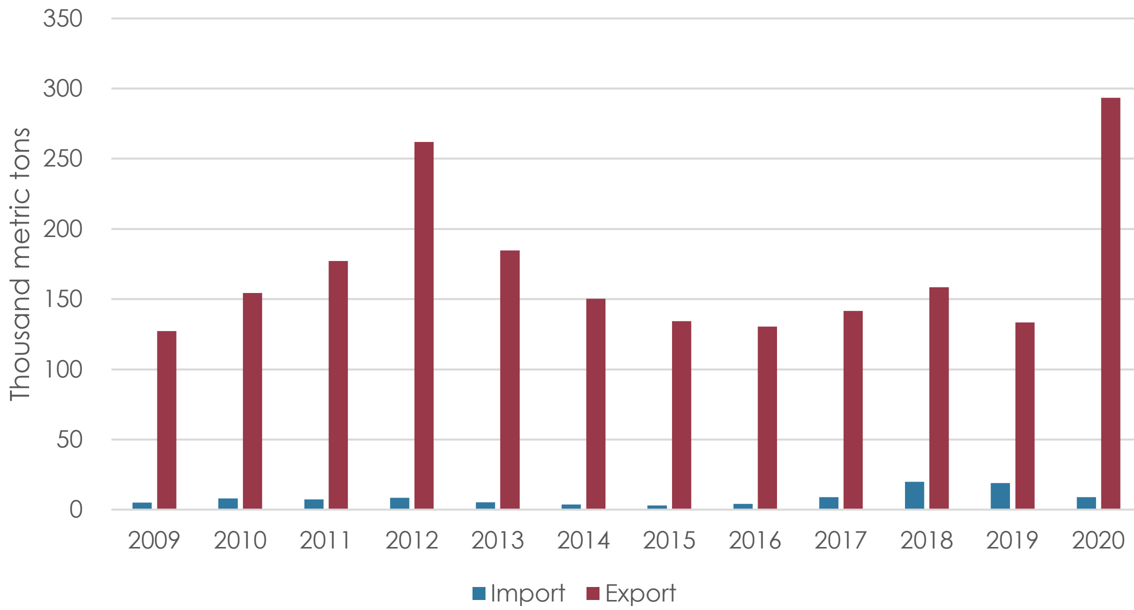

Figure 18. U.S. imports and exports of inedible oils and fats under HS code 15 18 00

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).

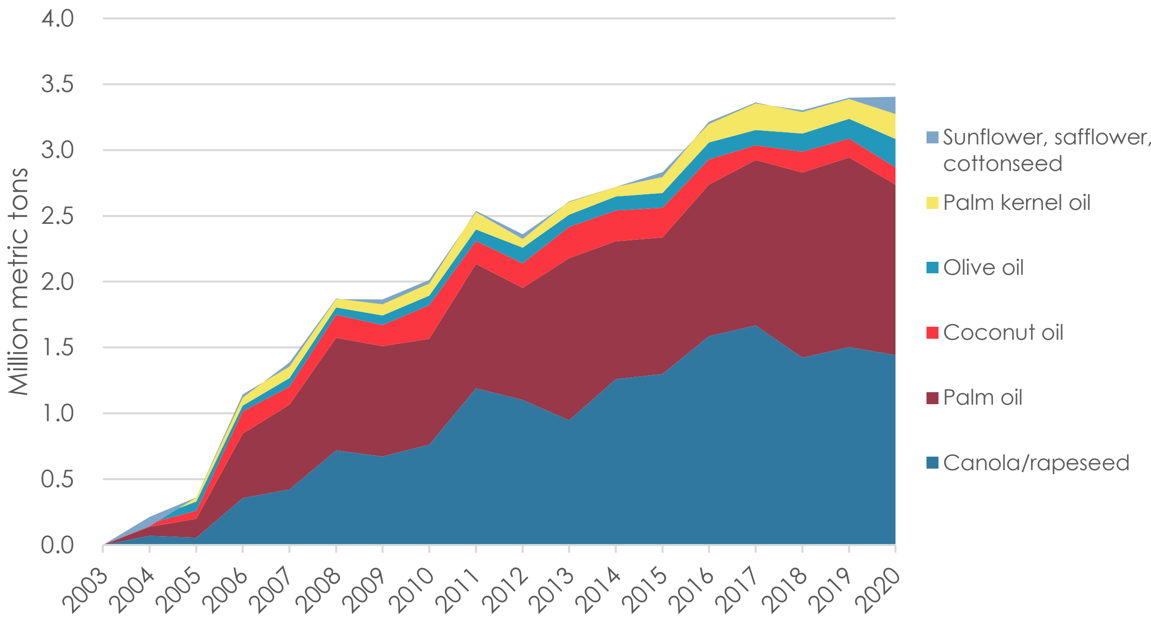

Figure 19. Increase in imports to the U.S. of major vegetable oils since 2003

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]

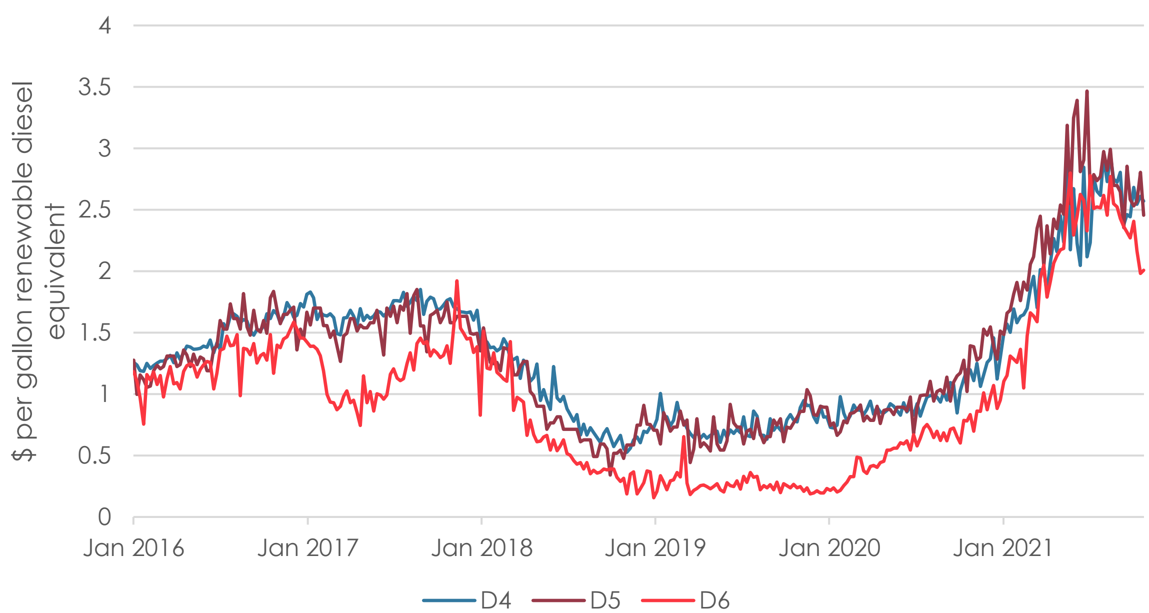

Figure 21. RIN prices in $ per gallon renewable diesel equivalent

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.

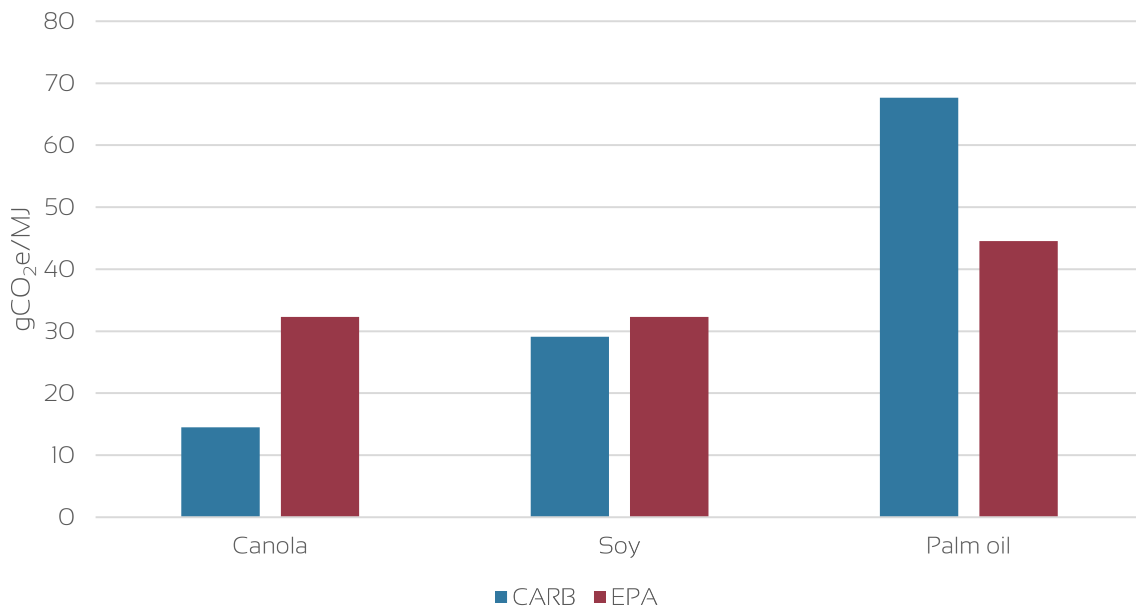

Figure 22. Estimated ILUC emissions from vegetable oil-based fuels

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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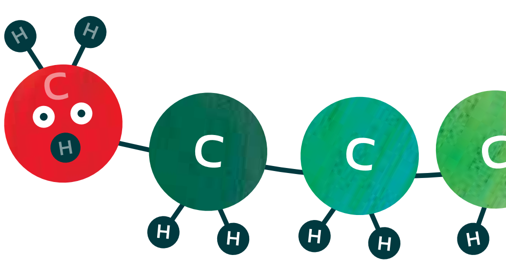
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Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.

charlesdavidson@me.com Hercules CA. 11 April 2022

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APPLICATION & PERMIT CENTER

11 April 2022

Re: Appeal of Contra Costa County Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project (File No. LP20-2040 and the Contra Costa County Code, section 26-2.2406)

To the Contra Costa County Board of Supervisors:

The appellant requests that the Board of Supervisors grant this appeal, to reject certification of the Phillips 66 Rodeo Renewed Project FEIR, and instruct the Contra Costa County Department of Conservation and Development and the Planning Commission to develop a revised DEIR, that meets the requirements of CEQA, to be prepared and circulated for public comment.

The County planning commission decision to certify the Final Environmental Impact Report 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 argument set forth in this appeal letter; the comments submitted concerning the draft Environmental Impact Report (DEIR) and the failure of both the DEIR and the FEIR to comply with the California Low Carbon Fuel Standard.

Inconsistency with California climate pathways.
The Comments presented and this appeal presents detailed analysis of Phillips 66's refinery-level CO2 carbon intensity ("CI"; CO2 greenhouse gas emissions) of "Renewable Diesel" ("RD"), the biodiesel product, for the Rodeo Renewed Project.

Instead of being a low-carbon fuel, the Phillips 66 San Francisco Refinery's anticipated post-Project RD CO2 greenhouse gas emissions (produced during the hydrocracking of animal fats and vegetable oils, on a per barrel basis), would greatly exceed the CO2 emissions of the refinery's current average high-sulfur, heavy petroleum feedstock.

The Phillips 66 Rodeo Renewed Project Draft Environmental Impact Report (DEIR) and Final EIR did not acknowledge that making refinery biodiesel, or so-called renewable diesel, from hydrogenated vegetable oils and animal fats is as energy-consuming or carbon-intensive to refine as the world's dirtiest, most dense and highest sulfur crude oils.

However, if the Phillips 66 were to acknowledge this fact, the refinery would have to contradict their own assertions that their Project's renewable diesel product is not a low-carbon fuel. The actual numbers published in Phillips 66's own DEIR for their Project, which stipulated expected energy usage, hydrogen requirements and CO2 greenhouse gas emissions, when analyzed, clearly indicate that their renewable diesel (on per barrel basis) is extraordinarily energy-intensive to process and "carbon-intensive".

Instead of being a low-carbon fuel feedstock, animal fat and vegetable oil molecules are triglycerides, like the kind that your doctor measures, and they, counterintuitively, are far more difficult to crack than petroleum oils. The most energy-intensive hydrocracking process for renewable diesel is the hydro-deoxygenation reaction, for which the refinery must greatly expand it hydrogen usage.

In the public or political sphere, if renewable diesel were understood as not being a true low-carbon diesel substitute, then such projects would not be certified to qualify for and be approved for California Low Carbon Fuel Standard (LCFS) credits and Federal subsidies.

Uniquely, the Phillips 66 refinery in Rodeo Contra Costa County, is planning on being the world's largest Renewable Diesel biofuels refinery in the world and is about 12 miles away from the Martinez Marathon refinery, which is planning on being the world's second largest biofuels refinery.

For its part, Marathon proudly claims a reduction in carbon dioxide greenhouse gasses of 60% in their renewable diesel project. However, that 60% CO2 reduction comes entirely from the 60% smaller daily throughput specified by the project and is entirely NOT from the decreased carbon intensity of the renewable diesel, itself. (1)

Similar for Phillips 66, which will experience a minimum 33% decrease in throughput (from a 4-year pre-COVID average capacity utilization) from 105,000 barrels per day to a maximum of 80,000 bpd. However, at both refineries, the per barrel CO2 carbon intensities for renewable diesel will actually increase significantly (despite the decrease in throughput), because of the corresponding large increase in hydrogen needed for hydrocracking triglyceride oils. (2a-d)

For example, despite the shimmer of Marathon's 60% decrease in throughput, a simple look at their 42% *increase* in total hydrogen production (made from fossil-fuels), combined with their simultaneous *decreased* throughput, results in a 32% per barrel *increase* in carbon intensity. (1)

Marathon (calculations based on reference #1):

Decrease in total refinery throughput:
(120,000 – 48,000 = 72,000) / 120,000 = 0.6 = - 60% decrease in throughput
Decrease in total refinery-wide CO2:
1145000 / 2169000 = 0.5278 = - 53% decrease in CO2

Marathon: Total Refinery CO2
Pre-Project (Baseline):

Barrels: 120,000 bbl/d * 365 = 43,800,000 bbl/y
CO2 Refinery-wide total: 2169000 mt/y * 1000 = 2169000000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2169000 * 1000 / 43800000 = 49.52 CO2 kg/bbl

Post Project: Total Refinery CO2
Barrels: 48000 bbl/d * 365 = 17,520,000 bbl/y
CO2 Refinery-wide total: 1,145,000 mt/y * 1000 = 1,145,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 1,145,000,000 / 17,520,000 = 65.35 CO2 kg/bbl

Pre-to-Post project *per barrel* change in Carbon Intensity (Relative % - refinery-wide):
65.35 / 49.52 = 1.32 = + 32% → +32% increase in CI

Pre-to-Post project hydrogen production increase (project total):
962,000 / 678,000 = 1.42 → **+ 42% (increase in total H2-plant CO2 emissions)**

Again, similar to Marathon, post-Project, Phillips will be producing 37% more hydrogen than with petroleum refining and delivering a renewable diesel product with a 36%-to-55% increase in per barrel Carbon Intensity at the refinery level. (2)

Phillips 66 (calculations based on references #2a, 2b, 2c and 2d):

Pre-Project: Total Refinery CO2:
Barrels: 105,000 bbl/d * 365 = 38,300,000 bbl/y
CO2 Refinery-wide total: 2,171,000 mt/y = 2,171,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,171,000,000 / 38,300,000 = 56.68 CO2 kg/bbl

Post Project: Total Refinery CO2 (low est.):
Barrels: 80,000 bbl/d * 365 = 29,200,000 bbl/y
CO2 Refinery-wide total: 2,147,000 my/y = 2.147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 / 29,200,000 = 73.53 CO2 kg/bbl

Post Project: Total Refinery CO2 (high est.):
Barrels: 67,000 bbl/d * 365 = 24,455,000 bbl/y
CO2 Refinery-wide total: 2,147,000 my/y = 2.147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 / 24,455,000 = 87.79 CO2 kg/bbl

Pre-to-Post project per barrel change in Carbon Intensity (Relative %):
a. 73.52 / 56.65 = 1.3 = + 30% → 30% increase in CI (low est.)
b. 87.79 / 56.65 = = 1.55 = + 55% → 55% % increase in CI (high est.)

Pre-to-Post project hydrogen Production increase (total from Air Liquide and unit U110):
(120 mscf +22) / (93 mscf + 12 mscf) = 142 mscf / 105 mscf = 1.35 → +35% (increase in H2 production)

The projected Phillips 66 and Marathon Renewable Diesel products, when compared to the processing energy requirements for heavy petroleum refining, would be twice as carbon intensive as the average U.S. refinery's processing of petroleum and as high or higher than the most carbon intensive refineries. (3-7)

> ***[Note see reference #6 for calculations of Phillips 66 and Marathon's estimated increased CO2 emissions for refinery-level (midstream) renewable diesel production via hydrocracking compared to high-sulfur, heavy petroleum hydrocracking at another refinery (based on PRELIM 1.3).*** *And see ref. #7; J. Bergerson, Nature. Avg. US midstream carbon intensity: 40.7 kgCO2e/kg)]*

So, what is currently being proposed in Contra Costa County, at the Phillips 66 Refinery, as well as the Marathon Refinery, are very expensive, publicly-funded carbon-intensive renewable diesel projects, which are erroneously being promoted as sources of low-carbon fuel.

As the availability of used cooking oils and waste animal fat markets will be competitive and limited once multiple large refineries enter the renewable diesel business, the default principal feedstock is expected to be soybean oil. At a yield of only 57 gallons of soybeans per acre, however, Phillips 66 alone could annually use up to 33,000 square miles of soybean acreage or nearly the size of the State of Indiana, for its expected 1.22 billion gallons of renewable diesel produced yearly. (8)

Finally, refinery biodiesel is being funded to the tune of up to $3.32 per gallon (according to Stratas Advisers, and depending on the feedstock). That could amount to up to $3 billion *yearly* given to Phillips 66 and $1.8 billion given to Marathon under false pretenses as producers of low carbon biofuels, which flies in the face of a massive increase in *per barrel* carbon intensity and global food security. (9)

REFERENCES:

1) Marathon Renewable Project (Martinez CA; PowerPoint Presentation):

Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.
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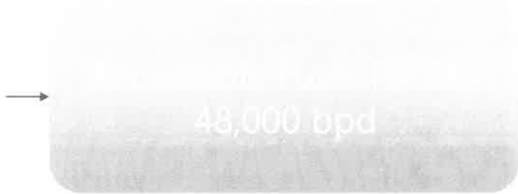

1	Marathon Martinez	Refinery	Renewables	Delta Mtonnes/Yr
2	Capacity (mbpd)	160	48	
3	MPC GHG H2 Production (MTonnes/Yr)	448	687	239
4	AP GHG H2 Production (MTonnes/Yr)	230	275	45
5	GHG H2 Captured & Sold (MTonnes/Yr)	-56	-56	-
8	GHG All Other Combustion (MTonnes/Yr)	1547	239	-1,308
9	***Total Direct GHG w/ AP (MTonnes/Yr)***	***2169***	***1145***	***-1,024***

~ 60% reduction in GHG as part of project
Will continue to capture & sell 56,000 MT of CO2e

2a) Rodeo Renewed Project (Rodeo CA; 80 K or 67 K barrels per day); Pre-Project (current 105 K bpd):

Rodeo Renewed Project
Draft Environmental Impact Report

Table 4.8-2. Baseline Annual GHG Emissions (2019)[1]

Source Category	Baseline Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Refinery				
Ocean-going Vessels and Harbor Craft	15,137	0.15	0.93	15,418
Trucks	4,466	0.02	0.70	4,676
Rail	1,373	0.11	0.03	1,386
Facility Operations	1,333,341	91.96	11.74	1,338,911
Electricity	9,160	1.30	0.28	9,270
Rodeo Refinery Total	1,363,477	94	14	1,396,661
Air Liquide H_2 Plant	801,794	--	--	801,794
Santa Maria Site and Pipeline Sites				
Trucks	2,565	0.01	0.40	2,686
Rail	177	0.01	0.00	179
Facility Operations	171,765	17.30	1.43	172,571
Electricity	5,328	0.76	0.16	5,392
Total Statewide	2,345,107	111.62	15.68	2,352,284
Total within BAAQMD	2,165,272	93.54	13.69	2,171,455

[1] 2019 is the CEQA baseline for this analysis for all sources except ocean-going vessels and harbor craft. For vessel emissions, an average of 2017 through 2019 was used.
Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant Site
Air Liquide CO_2e emissions assumed to be entirely CO_2 as the breakdown for CH_4 and N_2O is not available.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. It is expected to change to 25 and 298 respectively for reporting years 2021 and forward.

2b) Rodeo Renewed Project (Rodeo CA); Post-Project (completed):

Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.

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Table 4.8-5. Total Annual Project Operational GHG Emissions

Source	Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Renewed Project Emissions				
Ocean Going Vessels and Harbor Craft	26,195	0.28	1.53	26,657
Rail	8,119	0.64	0.20	8,195
Trucks	2,720	0.00	0.43	2,847
Facility Stationary Sources	1,069,772	84.51	10.79	1,075,100
Electricity	1,180	0.41	0.09	2,889
Total Operational	**1,109,661**	**85.84**	**13.04**	**1,115,689**
Air Liquide H_2 Plant	1,031,689	--	--	1,031,689
Total Operational with Air Liquide	**2,141,350**	**85.84**	**13.04**	**2,147,378**
CEQA Impact Evaluation				
Baseline Emissions within BAAQMD	2,165,272	93.54	13.69	2,171,455
Project Minus CEQA Baseline				-24,077
Significance Threshold				10,000
Exceeds Threshold?				No
Statewide Impact Evaluation (Informational only)				
Baseline Emissions Statewide	2,345,107	112	16	2,352,284
Project Minus Statewide Baseline				-204,905

Notes: Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. Based on CARB reporting, it is expected to change to 25 and 298 respectively for reporting years 2021 and forward. Therefore, Project facility emissions are based on 25 GWP for CH_4 and a 298 GWP for N_2O.
The GHG emissions for the Air Liquide hydrogen plant are not reduced to reflect the offset provisions of the Settlement Agreement between ConocoPhillips Company and the Attorney General of California, dated September 10, 2007, and amended May 25, 2010.
Air Liquide CO_2e emissions assumed to be entirely CO_2 as breakdown for CH_4 and N_2O is not available.

2c) Air Liquide Hydrogen Plant H2 production; Table 15; Attachment B, Appendix B:

Stationary Source Table 15
Air Liquide Hydrogen Plant Emissions Summary
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

CAP and GHG Emissions				Pre-Project Emissions (tons/year)						
Scaling Method	Baseline Activity	Project Activity	Units	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
Fuel Combustion	758	987	MMBTU/hr	17	0.010	0.95	1.1	3.6	3.5	--
Hydrogen Production	93.26	120	MMSCF H2/day	--	--	--	--	--	--	801,794
			Total	17	0.010	0.95	1.1	3.6	3.5	801,794

Scaling Method	Post-Project Emissions (tons/year)							Change in Emissions (tons/yr)						
	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
Fuel Combustion	22	0.013	1.2	1.4	4.7	4.6	--	5.1	0.0031	0.29	0.34	1.1	1.1	--
Hydrogen Production		--	--	--	--	--	1,031,689	--	--	--	--	--	--	229,895
Total	22	0.013	1.2	1.4	4.7	4.6	1,031,689	5.1	0.0031	0.29	0.34	1.1	1.1	229,895

2d) Unit U110 Phillips 66 Hydrogen Plant H2 Production; table 13; Attachment B, Appendix B:

Stationary Source Table 13
Baseline and Post-Project TAC Emissions from Miscellaneous Project Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source ID	Description	Post-Project Status	Emission Type	Baseline Throughput		Post-Project Throughput	
				Rate	Units	Rate	Units
11	U240 B-201 Heater	Operational	Combustion	56	MMBtu/hr	33	MMBtu/hr
12	U240 B-202 Heater	Operational	Combustion	16	MMBtu/hr	24	MMBtu/hr
13	U240 B-301 Heater	Operational	Combustion	125	MMBtu/hr	93	MMBtu/hr
45	U246 B-801 A/B Heater	Operational	Combustion	62	MMBtu/hr	24	MMBtu/hr
427	Unit 110 Hydrogen Manufacturing Unit	Operational	Hydrogen Plant	12	MMScf/day	22	MMScf/day
433	U110 H-1 Furnace (H2 Plant Reforming)	Operational	Combustion	140	MMBtu/hr	225	MMBtu/hr

Source ID	Baseline Emissions[1] (tons/year)							Post-Project Emissions[2] (tons/year)						
	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
11	11	13	0.39	1.2	1.6	1.6	29,233	6.8	8.0	0.23	0.71	1.0	1.0	17,492
12	1.8	3.8	0.42	0.34	0.46	0.46	8,271	2.8	5.8	0.64	0.51	0.71	0.71	12,607
13	6.9	30	0.87	2.7	3.7	3.7	66,329	5.2	22	0.65	2.0	2.7	2.7	49,541
45	1.4	0.12	0.82	0.26	0.81	0.81	[illegible]	0.52	0.046	0.32	[illegible]	0.31	0.31	[illegible]
427	--	--	--	--	--	--	130,368	--	--		--	--	--	177,642
433	3.6	4.1	1.3	0.15	4.6	4.6	16,351	5.8	6.2	2.1	0.24	7.4	7.4	26,133

Notes:
1. Baseline emissions were obtained directly from the facility's 2019 BAAQMD Rule 12-15 Emissions Inventory.
2. Post-project emissions were estimated using baseline throughput and emissions and post-project projected rates.

3) Hydrotreating in the production of green diesel. Rasmus Egeberg, Niels Michaelsen, Lars Skyum and Per Zeuthen. *Haldor Topsøe.*

"As the reactions also consume large amounts of hydrogen (for a 100% renewable feed, a hydrogen consumption of 300–400 Nm^3/m^3 is not unusual), higher make-up hydrogen and quench gas flows are needed even when co-processing quite small amounts."

> 400 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) = 2451.61 scf/bbl (2451 / 423) = 5.79 kg/bbl * 9.1 = 52.69 CO2 kg/bbl (hydrogen only)
>
> 300 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) * 0.75 [(300nM3/M3) / 400 (NM3/M3)]= 1838.70 scf/bbl = (1838.7 / 423) = 4.34 kg/bbl = 39.5 CO2 kg/bbl (hydrogen-production only).

4) PATENTED HYDROCRACKER HYDROGEN USAGE FOR AGAEL BIOFUELS REFINING COMPARED TO SOY OIL. [Pub.No.:US2010/0297749A1 ARAVANIS et al. METHODS AND SYSTEMS FOR BIOFUEL PRODUCTION. Pub.Date: Nov.25,2010] (12)

For comparison of algael oil hydrorefining to soy oil and heavy petroleum hydrorefining, a patented algael biofuels protocol was described for hydrocracking, plus hydroisomerization and feedstock hydrotreating, of 80 barrels per day throughput using 245,000 scfd of hydrogen plant H2. The total hydrogen volume required for the described "Integrated Biofuels Refinery" for algael oil is 3,063 scf per barrel, which would place the algael fuel hydrocracker hydrogen consumption at the upper (heavy petroleum) end of the 1,000-3,000 scf per barrel range. Similar large- and small-size algael biofuels hydrorefinery configurations were described in the patent.

5) Changing Hydrocarbons Midstream. Karras, Greg. Community Energy Resource. Table 2. https://www.energy-resource.com/_files/ugd/bd8505_757a3372387d46358c74d958d158fcb5.pdf

Changing Hydrocarbons Midstream

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.

5) ENERGY STAR® Guide: ENERGY STAR is a U.S. Environmental Protection Agency Program for Energy and Plant Managers. (February 2015)
https://www.energystar.gov/sites/default/files/tools/ENERGY_STAR_Guide_Petroleum_Refineries_20150330.pdf

The hydrocracker consumes energy in the form of fuel, steam and electricity (for compressors and pumps)...The reactions are carried out at a temperature of 500-750°F (290-400°C) and increased pressures of 8.3 to 13.8 Bar...The hydrocracker also consumes energy indirectly in the form of hydrogen. The hydrogen consumption is between 150 and 300 scf/barrel of feed (27-54 Nm^3/bbl) for hydrotreating and 1000 and 3000 scf /barrel of feed (180-540 Nm^3/bbl) for the total plant (Gary et al., 2007).

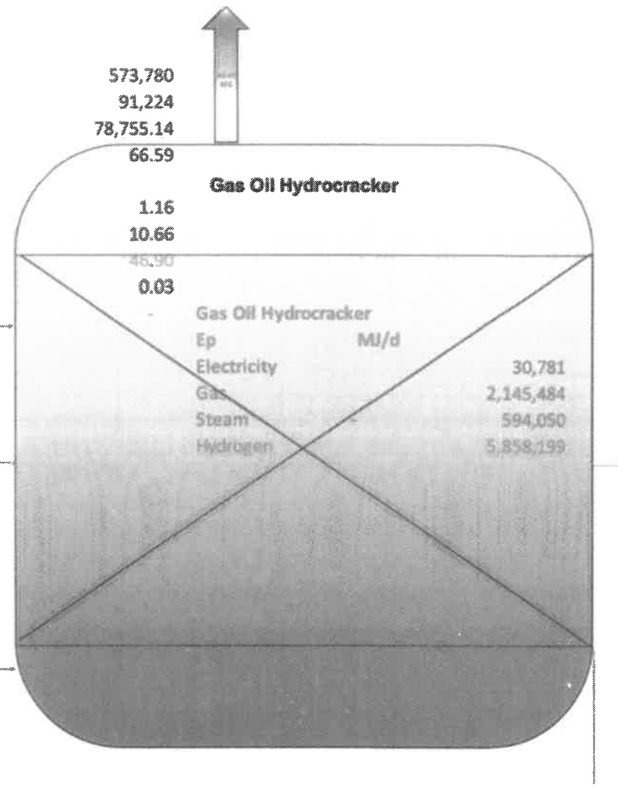
6) Petroleum Refinery Life Cycle Inventory Model (PRELIM) PRELIM v1.3. User guide and technical documentation. Jessica P. Abella et al. [Joule A. Bergerson]
https://www.ucalgary.ca/sites/default/files/teams/477/prelim-v1.3-documentation.pdf
PRELIM 1.3 Hydrocracker with heavy, high-sulfur petroleum feedstock:
14.96 API and 3.35% Sulfur

Gas Oil HC Fuel Gas

Property	Units	
Vol Flow	bpd	573,780
Vol Flow	m^3/d	91,224
Mass Flow	kg/d	78,755.14
Sulphur	wt%	66.59
API gravity	°API	
Density	kg/m^3	1.16
Hydrogen	wt%	10.66
DHc	MJ/kg	46.90
Price	$/bbl	0.03
Allocation	Hydrogen Content Basis	-

Gas Oil Hydrocracker Feed

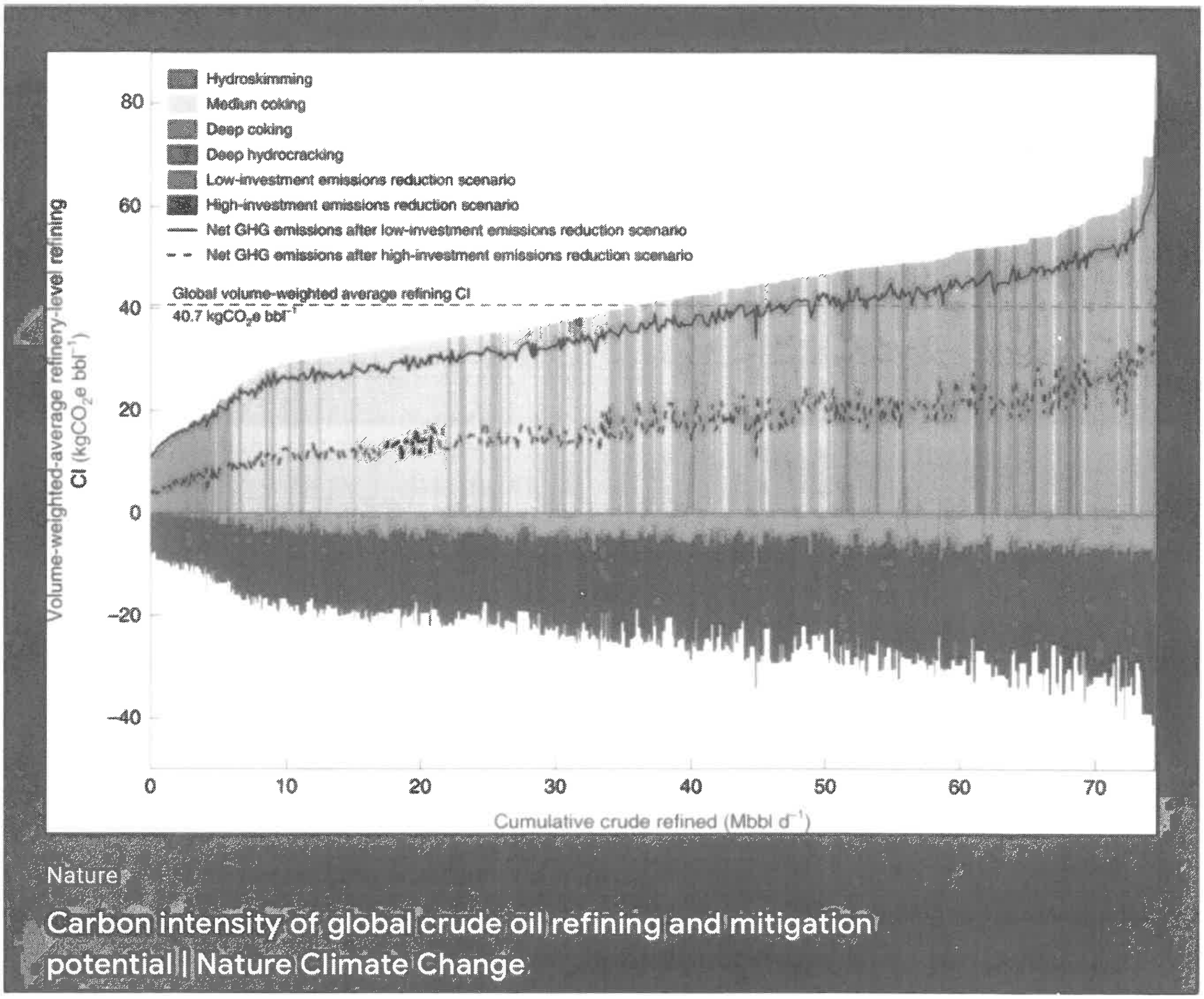
Property	*Units*	
Vol Flow	bpd	10,199.87
Vol Flow	m^3/d	1,621.65
Mass Flo\	kg/d	1,566,698.34
Sulphur	wt%	3.35
API gravity		14.96
Density	kg/m^3	966.11
Hydrogen	wt%	11.18
MCR	wt%	-
Total hyd	kg/d	43,911.28
DHc	MJ/kg	39.29
Price	$/bbl	85.54
Allocatior	Hydrogen Content Basis	-



PRELIM petroleum-to-Marathon Renewable Project (+32% increase example; predicted Renewable Diesel CI)
Per barrel biofuels CO2 GHGs +32% inc. over petroleum:
Hydrogen per barrel: 44000 (H2/d) / 10200 (bbl/d) * 9.8 * 1.32 = 55.80 kg/bbl
Hydrocracker energy per day: 5858000 + 2145000 + 594000 + 31000 = 8628000
Share of total energy above hydrogen-only energy: 5858000 + 2145000 + 594000 + 31000 / 5858000 = 1.47
Per barrel biofuels predicted carbon intensity: 1.47 * 55.8 = 82.19 CO2 kg/bbl

PRELIM petroleum-to-Rodeo Renewed Project (high and low estimates; predicted Renewable Diesel CI)
44000 / 10200 * 9.8 * 1.47 * 1.30 = 80.78 CO2 kg/bbl (+30% low case est.)
44000 / 10200 * 9.8 * 1.47 * 1.55 = 96.32 CO2 kg/bbl (+55% high case est.)

7) Carbon intensity of global crude oil refining and mitigation potential. Liang Jing et al. *Nature Climate Change* volume 10, pages 526–532 (J. Bergerson; 2020). The global-weighted carbon intensity at crude level is 10.1 – 72.1 kg CO2e/bbl, with a weighted average of 40.7 kgCO2e/kg.



8) Biodiesel. S Sadaka. (FSA1050: DIVISION OF AGRICULTURE RESEARCH & EXTENSION University of Arkansas System). < https://www.uaex.uada.edu/publications/PDF/FSA-1050.pdf>

9) Overcapacity Looms as More and More US Refiners Enter Renewable Diesel Market. Stratas Advisors. (June 11, 2020) <https://stratasadvisors.com/Insights/2020/06112020LCFS-RD-Investment>

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Contra Costa Board of Supervisors,
and
County Planning Commission of the
Contra Costa County Department Of Conservation And Development;

As the Directors of the Crockett Community Foundation, we are respectfully requesting an appeal of the Commission's decision to recommend approval of the Phillips 66 Rodeo Renewed project as currently described in the Staff Report. The mission of the Crockett Community Foundation is to enhance the quality of life in the Community, now and for generations to come.

Our grounds for **appeal** are as follows:

- The details of the Community Benefits Agreement or the conditions of the project are insufficiently defined as to the magnitude or nature of any actual benefit.

- Crockett has already been classified as a disadvantaged community by Contra Costa County. Senate Bill (SB) 1000, which requires Contra Costa County to integrate environmental justice into the General Plan. This law is based on the understanding that some communities have experienced a combination of historic discrimination, negligence, and political and economic disempowerment, with the result that today they are struggling with both a disproportionate burden of pollution and health impacts and disproportionate social and economic disadvantages.

- The town of Crockett was not specifically mentioned in the conditions of compensatory funding or the mechanism by which this would be carried out, nor as a future beneficiary of the Community Benefits Agreement. Crockett lies downwind of the proposed project and quality of life in Crockett will be directly affected by air and water pollutants, noise pollution from an increase of rail traffic and potential transportation related hazards from the proposed water, highway and rail traffic.

- The Crockett Community Foundation(CCF) was not mentioned in the conditions. The CCF was founded as an organization to distribute community benefit funds awarded as compensation for the Unocal Catacarb chemical release in 1994. We have also acted as the distributor of compensatory funds for the Crockett Cogen facility. In total we have 27 years of experience distributing funds in the community, and feel we are the best qualified organization to do so.

- The CCF was not notified in advance of the hearing. Crockett Community Foundation is an obvious and significant organization in the area; as such we feel the county was remiss in its failure to notify the CCF of the hearing on March 30.

The Crockett Community Foundation is non-profit managed by elected Directors with experience managing/dispersing community benefit funds for Crockett, Tormey and Port Costa. We are responsible for managing the funds from financial settlements following the Unocal Refinery's Catacarb release in 1994 as well as the settlement funds with the Crockett Cogeneration Good Neighbor agreement.

Crockett is a working class community located on the shoreline, adjacent to Railroad and Highways, and downwind from the proposed Project. Crockett's residents have been regularly subjected to leaks and hazards of the refinery, and are greatly concerned about future activity at the refinery.

While in general Crockett appreciates the need for employment opportunities and the idea of environmentally friendly innovation, possible with this project, we at the CCF feel that the above appeal needs to be addressed prior to approval of the project.

We would expect that Crockett be recognized as impacted by any changes or development at the Phillips 66 refinery and that CCF be included in any discussions associated with the proposed distribution of funds related to a decision to move this project forward.

Our expectation is that you address all concerns before rendering any decision and that we, the Crockett Community Foundation be included in any decisions impacting the quality of life in our community.

Respectfully,

Brian Montgomery, President
The Crockett Community Foundation

MITIGATION MONITORING AND REPORTING PROGRAM

Phillips 66 Rodeo Renewed Project

Introduction

The California Environmental Quality Act (CEQA) requires a Mitigation Monitoring and Reporting Program (MMRP) for projects where mitigation measures are a condition of project approval and development. The Contra Costa County Conservation and Development Department prepared an Environmental Impact Report in response to Phillips 66 application for a land use permit to modify the existing Rodeo Refinery into a repurposed facility that would process renewable feedstocks into renewable diesel fuel, renewable components for blending with other transportation fuels, and renewable fuel gas.

Project Overview

Repurposing of the Rodeo Refinery would assist California in meeting its stated goals of reducing greenhouse gas emissions and ultimately transitioning to carbon neutrality. It would also provide a mechanism for compliance with California's Low-Carbon Fuel Standard and Cap and Trade programs and the federal Renewable Fuels Standard, while continuing to meet regional market demand for transportation fuels.

The Project would produce up to 55,000 bbrl/d of a variety of renewable transportation fuels from renewable feedstocks. The Rodeo Refinery as a whole post-Project would produce up to 67,000 bbrl/d. To maintain current facility capacity to supply regional market demand for transportation fuels, including renewable and conventional fuels, the post-Project facility configuration could receive, blend, and ship up to 40,000 bbrl/d of gasoline and gasoline blendstocks.

Because the Project would discontinue processing crude oil at the Rodeo Refinery, other sites owned and operated by Phillips 66 located throughout the state would be affected. Therefore, the Project consists of activities at the following four sites:

- Rodeo Site—is within the Rodeo Refinery where the proposed modifications would occur.
- Carbon Plant—is within the Rodeo Refinery in nearby Franklin Canyon and would no longer be necessary. It would be demolished.
- Santa Maria Refinery—is located in San Luis Obispo County and would no longer be necessary to provide semi-refined feedstock to the Rodeo Refinery. It would be demolished.
- Pipeline Sites—these collect crude oil for the Santa Maria Refinery and deliver semi-refined feedstock to the Rodeo Refinery and, therefore, would not be necessary. The pipelines would be cleaned and taken out of service, or sold.

Purpose of the MMRP

This MMRP has been prepared in conformance with CEQA (Public Resources Code section 21081.6) and CEQA Guidelines section 15097. The MMRP is based on the information and mitigation measures contained in the EIR for the Project. Pursuant to Public Resources Code section 21081.6(b), each of the mitigation measures identified in the MMRP will be included as enforceable permit terms in any permit issued by Contra Costa County. The purpose of this MMRP is to:

- Verify compliance with the mitigation measures identified in the EIR;
- Provide a framework to document implementation of the mitigation measures included in the EIR;
- Provide a record of mitigation requirements;

- Identify monitoring and enforcement agencies;
- Establish and clarify administrative procedures for the clearance of mitigation measures;
- Establish the frequency and duration of monitoring; and
- Utilize the existing agency review processes wherever feasible.

Phillips 66 as the Permittee shall be responsible for implementing each mitigation measure and shall be obligated to provide verification to the appropriate monitoring and enforcement agencies that each mitigation measure has been implemented. The Permittee shall maintain records demonstrating compliance with each mitigation measure. Such records shall be made available to the Contra Costa County Conservation and Development Department upon request.

All documents and other information that constitute the public record for this project shall be maintained by the Contra Costa County Conservation and Development Department and shall be available for public review at the following address:

Contra Costa County
Conservation and Development Department
30 Muir Road, Martinez CA 94553

Organization

As shown in the following table, each mitigation measure for the Project is listed and categorized by impact area, with identification of:

- Implementation Schedule – The phase of the Project during which the mitigation measure shall be monitored; relevant phases include pre-construction, construction, and operation and maintenance.
- Responsible Party – The party responsible for implementing each mitigation measure and providing verification of implementation.
- Monitoring/Enforcement – The agency, or agencies, responsible for monitoring the compliance and implementation, and enforcement of the mitigation measure.

MMRP Modification

Minor changes and modifications to the MMRP are permitted, subject to Contra Costa County Conservation and Development Department approval. Contra Costa County Conservation and Development Department, in conjunction with appropriate agencies, will determine the adequacy of any proposed change or modification, and whether the change or modification requires additional environmental review. This flexibility is sometimes necessary to protect the environment with a workable program. No changes will be permitted unless the MMRP continues to satisfy the requirements of CEQA, as determined by the Contra Costa County Conservation and Development Department.

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Air Quality				
Mitigation Measure AQ-1: Implement BAAQMD Basic Control Measures Construction contractors shall implement the following applicable BAAQMD basic control measures as best management practices (BMPs): • All exposed surfaces (e.g., parking areas, staging areas, soil piles, graded areas, and unpaved access roads) shall be watered two times per day. • All haul trucks transporting soil, sand, or other loose material offsite shall be covered. • The permittee shall not cause or allow track-out at any active exit from the site onto an adjacent paved public roadway or shoulder of a paved public roadway that exceeds cumulative 25 linear feet and creates fugitive dust visible emissions. All visible mud or dirt track-out onto adjacent public roads shall be removed using wet power vacuum street sweepers within 4 hours of when the owner/operator identifies such excessive track-out on San Pablo Avenue, between the refinery and Interstate 80, and on the access roads between the Carbon Plant and Highway 4. The use of dry power sweeping is prohibited. • All vehicle speeds on unpaved roads shall be limited to 15 miles per hour. • All roadways, driveways, and sidewalks to be paved shall be completed as soon as possible. Building pads shall be laid as soon as possible after grading unless seeding or soil binders are used. • Idling times shall be minimized either by shutting equipment off when not in use or reducing the maximum idling time to 2 minutes as recommended by the BAAQMD, and not to exceed 5 minutes as required by the California airborne toxics control measure Title 13, Section 2485 of the California Code of Regulations (CCR). Clear signage shall be provided for construction workers at all access points. • Monitor the extent of the trackout at each active exit from the site onto a paved public road at least twice during each workday, at times when vehicle traffic exiting the site is most likely to create an	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development; BAAQMD	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
accumulation of trackout, or as otherwise specified by the Air District. • Document the active exit locations monitored each workday. • Document each occasion when the trackout exceeds cumulative 25 linear feet and all trackout control and cleanup actions initiated as a result of the above monitoring. • Maintain these records for at least five years, in electronic, paper hard copy or log book format, and make them available to the Air District upon request. • All construction equipment shall be maintained and properly tuned in accordance with manufacturer's specifications. • All equipment shall be checked by a certified mechanic and determined to be running in proper condition prior to operation. • Post a publicly visible sign with the telephone number and person to contact at the Lead Agency regarding dust complaints. This person shall respond and take corrective action within 48 hours. The Air District's phone number shall also be visible to ensure compliance with applicable regulations. Construction contractors shall implement the following Advanced Construction Mitigation Measures: • All exposed surfaces shall be watered at a frequency adequate to maintain minimum soil moisture of 12 percent. Moisture content can be verified by lab samples or moisture probe. • All excavation, grading, and/or demolition activities shall be suspended when average wind speeds exceed 20 mph. • Wind breaks (e.g., trees, fences) shall be installed on the windward side(s) of actively disturbed areas of construction. Wind breaks should have at maximum 50 percent air porosity. • Vegetative ground cover (e.g., fast-germinating native grass seed) shall be planted in disturbed areas as soon as possible and watered appropriately until vegetation is established. • The simultaneous occurrence of excavation, grading, and ground-disturbing construction activities on the same area at any one time				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
shall be limited. Activities shall be phased to reduce the amount of disturbed surfaces at any one time. • All trucks and equipment, including their tires, shall be washed off prior to leaving the site. • Site accesses to a distance of 100 feet from the paved road shall be treated with a 6 to 12 inch compacted layer of wood chips, mulch, or gravel. • Sandbags or other erosion control measures shall be installed to prevent silt runoff to public roadways from sites with a slope greater than one percent.				
Mitigation Measure AQ-2: Implement a NOx Mitigation Plan Phillips 66 shall prepare a NOx Mitigation Plan (NM Plan) prior to the issuance of construction-related permits for site preparation. The purpose of the NM Plan is to document expected construction and transitional phase NOx emissions in detail; and, if necessary, to identify feasible and practicable contemporaneous measures to reduce aggregated construction and transition NOx emissions to below the BAAQMD's 54 pounds per day threshold of significance. The NOx emissions estimate for the Project shall include consideration of readily available NOx construction and transition emission reduction measures, and/or other emission reduction actions that shall be implemented during construction and transitional phase of the Project. The NM Plan shall describe the approximate amount of NOx emissions reductions that will be associated with each action and reduction measure on a best estimate basis. The NM Plan shall be submitted to the Contra Costa County Department of Conservation and Development and the BAAQMD for review and approval, or conditional approval based on a determination of whether the NM Plan meets the conditions described below. The NM Plan shall include those recommended measures listed below needed to reduce the Project's construction and transition NOx emissions to less than the BAAQMD's threshold of significance. The NM Plan shall include a detailed description of the NOx emissions for all construction and transition activities based on BMPs and use data at the time of Project approval and current estimation protocols and methods. The plan shall, at a minimum, include the following elements: **1. Project Construction and Transition NOx Emissions**	Prior to BAAQMD permit issuance	Phillips 66	Contra Costa County Conservation and Development; BAAQMD	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
The Project's construction and transition NOx emission estimates presented in the NM Plan will be based on the emission factors for off-road and on-road mobile sources used during construction and transition, over and above baseline, along with the incorporation of vehicle fleet emission standards. Project construction and transition NOx emission estimates will be based upon the final Project design, Project-specific traffic generation estimates, equipment to be used onsite and during transition, and other emission factors appropriate for the Project prior to construction. The methodology will generally follow the approach used in this Draft EIR and in Appendix B. **2. NOx Emission Reduction Measures** The NM Plan shall include feasible and practicable NOx emission reduction measures that reduce or contemporaneously offset the Project's incremental NOx emissions below the threshold of significance. Planned emission reduction measures shall be verifiable and quantifiable during Project construction and transitional phase. The NM Plan shall be consistent with current applicable regulatory requirements. Measures shall be implemented as needed to achieve the significance threshold and considered in the following order: (a) onsite measures, and (b) offsite measures within the San Francisco Bay Area Air Basin. Feasible[1] onsite and offsite measures must be implemented before banked emissions offsets (emission reduction credits) are considered in the NM Plan. **a. Recommended Onsite Emission Reduction Measures:** i. Onsite equipment and vehicle idling and/or daily operating hour curtailments; ii. Construction "clean fleet" using Tier 4 construction equipment to the maximum extent practicable; iii. Reductions in Vessel and/or Rail Traffic; iv. Other onsite NOx reduction measures (e.g., add-on NOx emission controls); or v. Avoid the use of Suezmax vessels to the maximum extent practicable.				

1 For the purposes of this mitigation measure, "feasible" shall mean as defined under CEQA "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
vi. To the maximum extent practicable, all off-road equipment shall use the highest tier engines available when zero emissions equipment is not available (e.g., Tier 4 construction, rail, marine vessels and equipment, including for any dredging activities). In place of Tier 4 engines, offroad equipment can incorporate retrofits such that emission reductions achieved equal or exceed that of a Tier 4 engine. Contra Costa County Department of Conservation and Development in its consideration of the NM Plan shall have the option to require daily NOx reductions at the Carbon Plant necessary to achieve the NOx daily emissions significance threshold. Daily idling of one kiln would provide sufficient NOx reductions to offset the Project's incremental NOx emissions to below the NOx daily emissions threshold of significance on individual days that construction emissions are estimated to potentially be above the daily NOx significance threshold. Additional measures and technology to reduce NOx emissions may become available during the Project construction and operation period. Such measures may include new energy systems (such as battery storage) to replace natural gas use, new transportation systems (such as electric vehicles or equipment) to reduce fossil-fueled vehicles, or other technology (such as alternatively-fueled emergency generators or renewable backup energy supply) that is not currently available at the project-level. As provided in the NM Plan, should such measures and technology become available and be necessary to further reduce emissions to below significance thresholds, Phillips 66 shall demonstrate to the Contra Costa County Department of Conservation and Development and BAAQMD satisfaction that such measures are as, or more, effective as the existing measures described above. **b. Recommended Offsite Emission Reduction Measures:** Phillips 66, with the oversight of the Contra Costa County Department of Conservation and Development and BAAQMD, shall reduce emissions of NOx by directly funding or implementing a NOx control project (program) within the San Francisco Bay Area Air Basin to achieve an annual reduction equivalent to the total estimated construction NOx emission reductions needed to lower				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
the Project's NOx impact below the 54 pound per day significance threshold. The offsite measures will be based on the NOx reductions necessary after consideration of onsite measures. To qualify under this mitigation measure, the NOx control project must result in emission reductions within the San Francisco Bay Area Air Basin that would not otherwise be achieved through compliance with existing regulatory requirements or other program participation. Phillips 66 shall notify Contra Costa County within six months of completion of the NOx control project for verification. **3. Quarterly Verification Reports** Phillips 66 shall prepare and submit NM Verification Reports quarterly during the construction or transitional phase activities, while project construction or transitional phase activities at the site are ongoing. The reporting period will extend through the last year of construction. The purpose of the report is to verify and document that the total project construction and transitional phase NOx emissions for the previous year, based on appropriate emissions factors for that year and the effectiveness of emission reduction measures, were implemented. The report shall also show whether additional onsite and offsite emission reduction measures, or additional NOx controls, would be needed to bring the project below the threshold of significance for the current year. The report shall be prepared by Phillips 66 and submitted to the Contra Costa County Department of Conservation and Development and the BAAQMD for review and verification. NOx offsets for the previous year, if required, shall be in place by the end of the subsequent reporting year. If Contra Costa County and the BAAQMD determine the report is reasonably accurate, they can approve the report; otherwise, Contra Costa County and/or the BAAQMD shall identify deficiencies and direct Phillips 66 to correct and re-submit the report for approval.				
Mitigation Measure AQ-4: Odor Prevention & Management Plan Phillips 66 shall develop and implement an Odor Prevention & Management Plan (OPMP). The OPMP shall be an integrated part of daily operations at the Rodeo Site, to effect diligent identification and remediation of any potential odors generated by the Facility.	Obtain approval of OMP prior to Project operation; ongoing	Phillips 66	Contra Costa County Conservation and Development; BAAQMD	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
• The OPMP shall be developed and reviewed by the County in consultation with the BAAQMD prior to operation of the Project, and implemented upon commencement of the renewable fuels processes. • The OPMP shall be an "evergreen" document that provides continuous evaluation of the overall system performance, identifying any trends to provide an opportunity for improvements to the plan, and updating the odor management and control strategies as necessary. • The OPMP shall include guidance for the proactive identification and documentation of odors through routine employee observations, routine operational inspections, and odor compliant investigations. • All odor complaints received by the facility shall be investigated as soon as is practical within the confines of proper safety protocols and site logistics. The goal of the investigation will be to determine if an odor originates from the facility and, if so, to determine the specific source and cause of the odor, and then to remediate the odor. • The OPMP shall be retained at the facility for Contra Costa County, the BAAQMD, or other government agency inspection upon request.				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Biological Resources				
Mitigation Measure BIO-1a: Update Pre-Arrival Documents Phillips 66 shall update pre-arrival document materials and instructions sent to tank vessels agents/operators scheduled to arrive at the Marine Terminal with the following information and requests: • Available outreach materials regarding the Blue Whales and Blue Skies incentive program; • Whale strike outreach materials and collision reporting from NMFS; • Request extra vigilance by ship crews upon entering the Traffic Separation Scheme shipping lanes approaching San Francisco Bay and departing San Francisco Bay to aid in detection and avoidance of ship strike collisions with whales; • Request compliance to the maximum extent feasible (based on vessel safety) with the 10 knot voluntary speed reduction zone. • Encourage participation in the Blue Whales and Blue Skies incentive program.	Prior to the commencement of transitional phase; ongoing	Phillips 66	Contra Costa County Conservation and Development	
Mitigation Measure BIO-1b: California Department of Fish and Wildlife (CDFW) and Research Sturgeon Support Phillips 66 will conduct and support the following activities to further the understanding of vessel strike vulnerability of sturgeon in San Francisco and San Pablo Bay. Coordinate with CDFW and Research Sturgeon to ensure appropriate messaging on information flyers suitable for display at bait and tackle shops, boat rentals, fuel docks, fishing piers, ferry stations, dockside businesses, etc. to briefly introduce interesting facts about the sturgeon and research being conducted to learn more about its requirements and how the public's observations can inform strategies being developed to improve fisheries habitat within the estuary.	Prior to the commencement of transitional phase; ongoing	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Mitigation Measure BIO-3: Update and Review Facility Response Plan and Spill Prevention, Control, and Countermeasure Plan with OSPR • The Facility Response Plan and Spill Prevention, Control, and Countermeasure (SPCC) Plan shall be updated to address the Project operational changes, including changes in proposed feedstocks and types of vessels and trips. The SPCC shall address the operational changes of the Transitional Phase and post-Project. Phillips 66 will consult with OSPR during update of the SPCC Plan, especially adequacy of booms at the Marine Terminal to quickly contain a spill of renewable feedstocks • In accordance with CCR Title 14, Chapter 3, Subchapter 3, several types of drills are required at specified intervals. Due to the potential for rapid dispersion of biofuels and oils under high energy conditions, Phillips 66 shall increase the frequency of the following drills to increase preparedness for quick response and site-specific deployment of equipment under different environmental conditions. – Semi-annual equipment deployment drills to test the deployment of facility-owned equipment, which shall include immediate containment strategies, are required on a semiannual pass/fail basis – if there is fail during first six months, then another drill is required. Phillips 66 will require that both semi-annual drills are conducted and schedule them under different tide conditions. – An OSRO field equipment deployment drill for on-water recovery is required at least once every three years. Phillips will increase the frequency of this drill to annual. – CDFW-OSPR shall be provided an opportunity to help design, attend and evaluate all equipment deployment drills and tabletop exercises. To ensure this, Phillips 66 shall schedule annual drills during the first quarter of each year to ensure a spot on OSPR's calendar.	Prior to the commencement of transitional phase; ongoing	Phillips 66	Contra Costa County Conservation and Development	
Mitigation Measure BIO-4a: Prohibit Ballast Water Exchange Phillips 66 shall prohibit vessels from ballast water exchange at the Marine Terminal.	During operation and maintenance; ongoing	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Mitigation Measure BIO-4b: Update Pre-Arrival Documentation Phillips 66 shall update pre-arrival document materials and instructions sent to tank vessels agents/operators to ensure they are advised prior to vessel departure of California's Marine Invasive Species Act and implementing regulations pertinent to (1) ballast water management, and (2) biofouling management. Additionally, Phillips 66 will request that vessel operations provide documentation of compliance with regulatory requirements (e.g., copy of ballast water management forms and logs of hull husbandry cleaning/inspections).	Prior to the commencement of transitional phase; ongoing	Phillips 66	Contra Costa County Conservation and Development	
Cultural Resources				
Mitigation Measure CUL-1: Inadvertent Discovery of Archaeological Resources • Pursuant to CEQA Guidelines Section 15064.5(f), "provisions for historical or unique archaeological resources accidentally discovered during construction" shall be instituted. In the event that any cultural resources are discovered during ground-disturbing activities, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the County and a qualified archaeologist (as approved by the County) to assess the significance of the find pursuant to CEQA Guidelines Section 15064.5. If cultural resources are recovered on State lands, submerged or tidal lands, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the California State Lands Commission. If any find is determined to be significant, representatives of the County and the qualified archaeologist would meet to determine the appropriate course of action. • Avoidance is always the preferred course of action for archaeological sites. In considering any suggestion proposed by the consulting archaeologist to reduce impacts to archaeological resources, the County would determine whether avoidance is feasible in light of factors such as the nature of the find, project design, costs, and other considerations. If avoidance is infeasible, other appropriate measures (e.g., data recovery, interpretation of finds in a public venue) would be instituted. Work may proceed on other parts of the Project site while mitigation for archaeological resources is carried out. All significant cultural materials recovered shall be, at the discretion of the consulting archaeologist, subject to	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
scientific analysis, professional museum curation, and documented according to current professional standards.				
Mitigation Measure CUL-2: Inadvertent Discovery of Human Remains • The treatment of human remains and associated or unassociated funerary objects discovered during any ground-disturbing activity shall comply with applicable state law. Project personnel shall be alerted to the possibility of encountering human remains during Project implementation, and apprised of the proper procedures to follow in the event they are found. State law requires immediate notification of the County coroner, in the event of the coroner's determination that the human remains are Native American, notification of the California Native American Heritage Commission (NAHC), which would appoint a Most Likely Descendent (MLD) (PRC Section 5097.98). The MLD would make all reasonable efforts to develop an agreement for the treatment, with appropriate dignity, of human remains and associated or unassociated funerary objects (CEQA Guidelines Section 15064.5[d]). • The agreement shall take into consideration the appropriate excavation, removal, recordation, analysis, custodianship, curation, and final disposition of the human remains and associated or unassociated funerary objects. The PRC allows 48 hours to reach agreement on these matters. If the MLD and the other parties do not agree on the treatment and disposition of the remains and funerary objects, Phillips 66 shall follow PRC Section 5097.98(b), which states that "the landowner or his or her authorized representative shall reinter the human remains and items associated with Native American burials with appropriate dignity on the property in a location not subject to further subsurface disturbance."	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Geology and Soils				
Mitigation Measure GEO-1: Comply with Geotechnical Report Phillips 66 shall comply with and implement all of the following measures designed to reduce potential substantial adverse effects resulting from strong seismic ground shaking: • A California licensed geotechnical engineer or engineering geologist shall perform a comprehensive geotechnical investigation of all Project facilities based on adequate subsurface exploration, laboratory testing of selected samples, and engineering/geologic analysis of the data gathered. The information shall be compiled and presented as a geotechnical report that provides an evaluation of potential seismic and geologic hazards, including secondary seismic ground failures, and other geologic hazards, such as landslides, expansive and corrosive soils, and provides current California Building Code seismic design parameters, along with providing specific standards and criteria for site grading, drainage, berm, and foundation design. • For construction requiring excavations, such as foundations, appropriate support and protection measures shall be implemented to maintain the stability of excavations and to protect construction worker safety. Where excavations are adjacent to existing structures, utilities, or other features that may be adversely affected by potential ground movements, bracing, underpinning, or other methods of support for the affected facilities shall be implemented. • Recommendations in the approved geotechnical report shall be incorporated into the design and construction specifications and shall be implemented during build-out of the Project. • The Project geotechnical engineer shall provide observation and testing services during grading and foundation-related work, and shall submit a grading completion report to the County prior to requesting the final inspection. This report shall provide full documentation of the geotechnical monitoring services provided during construction, including the testing results of the American Society for Testing and Materials. The Final Grading Report shall	Prior to Contra Costa County Building Permit Issuance	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
also certify compliance of the as-built Project with the recommendations in the approved geotechnical report.				
Hazards Materials and Water Quality				
Mitigation Measure HAZ-1: Implement Release, Monitoring and Avoidance Systems The following actions shall be completed by Phillips 66 prior to Project operations, including the transitional phase, and shall include routine inspection, testing and maintenance of all equipment and systems conducted in accordance with manufacturers' recommendations and industry guidance for effective maintenance of critical equipment at the Marine Terminal. Feedstocks handled at the Marine Terminal are not regulated under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) (e.g. renewable feedstocks such as soybean oil and tallow) and therefore not subject to OSPR oversight, and are also not subject to the CSLC oversight efforts (MOTEMS, Article 5, Article 5.3 and Article 5.5, depending on the materials handled). Yet materials may be detrimental to the environment if spilled. Regulated products (i.e. "Oil" and "Renewable Fuels" defined in Pub. Resources Code sec. 8750) will continue to be transferred at the Marine Terminal, which do require MOTEMS-compliant Terminal Operating Limits for those products that reside within the jurisdiction of the CSLC. To ensure that Project operation continues to meet those standards, the following measures are required. **Applicability of MOTEMS, Article 5, 5.3, 5.5 and Spill Prevention Requirements** As some materials transferred at the terminal may be feedstocks or other non-regulated materials/feedstocks/products, Phillips 66 shall comply with the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (LKS Act) for all vessels calling at the Marine Terminal regardless of feedstock/material type. In addition, MOTEMs operational regulations, as codified in Article 5. Marine Terminals Inspection and Monitoring (2CCR §2300 et seq), Article 5.3 Marine Terminals Personnel Training and Certification (2CCR §2540 et seq), and Article 5.5 Marine Terminals Oil Pipelines (2CCR §2560 et seq), including items such as static liquid pressure testing of pipelines, shall be implemented for all operations at the Marine Terminal regardless of feedstock/material type and LKS Act regulatory status.	Prior to the commencement of transitional phase; ongoing	Phillips 66	California State Lands Commission	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Upon request, Phillips 66 shall provide evidence to relevant regulatory agencies that these facilities, operational response plans, and other applicable measures have been inspected and approved by CSLC and OSPR and determined to be in compliance. If terminal operations do not allow for regular compliance and inspection of LKS and MOTEMS requirements by the CSLC and OSPR, Philips 66 shall employ a CSLC-approved third-party to provide oversight as needed to ensure the same level of compliance as a petroleum-handling facility, and to ensure maximum protection of the environment from potential spills and resulting impacts. Phillips 66 shall provide evidence of compliance upon request of relevant regulatory agencies. **Remote Release Systems** The Marine Terminal has a remote release system that can be activated from a single control panel or at each quick-release mooring hook set. The central control system can be switched on in case of an emergency necessitating a single release of all mooring lines. However, to further minimize the potential for accident releases the following is required: • Provide and maintain mooring line quick release devices that shall have the ability to be activated within 60 seconds. • These devices shall be capable of being engaged by electric/push button release mechanism and by integrated remotely-operated release system. • Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s). • Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives. • In consultation with the CSLC and prior to Project operation, Phillips 66 shall provide a written evaluation of their existing equipment and provide recommendations for upgrading equipment to meet up-to-date best achievable technology standards and best industry practices, including but not limited to consideration of equipment updates and operational effectiveness (e.g. visual and				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
audible alarm options, data display location and functionality, optional system features). Phillips 66 shall follow guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4. • Best achievable technology shall address: – Functionality – Controlled release of the mooring lines (i.e. a single control system where each line can be remotely released individually in a controlled order and succession) vs. release all (i.e. a single control system where all lines are released simultaneously via a single push button). See SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.2.1. – Layout – The location(s) of the single control panel and/or central control system to validate that it is operationally manned such that the remote release systems can actually be activated within 60 seconds. This measure would allow a vessel to leave the Marine Terminal as quickly as possible in the event of an emergency (fire, explosion, accident, or tsunami that could lead to a spill). In the event of a fire, tsunami, explosion, or other emergency, quick release of the mooring lines within 60 seconds would allow the vessel to quickly leave the Marine Terminal, which could help prevent damage to the Marine Terminal and vessel and avoid and/or minimize spills. This may also help isolate an emergency situation, such as a fire or explosion, from spreading between the Marine Terminal and vessel, thereby reducing spill potential. The above would only be performed in a situation where transfer connections were already removed and immediate release would not further endanger terminal, vessel and personnel. **Tension Monitoring Systems** • Provide and maintain Tension Monitoring Systems to effectively monitor all mooring line and environmental loads, and avoid excessive tension or slack line conditions that could result in damage to the Marine Terminal structure and/or equipment and/or vessel mooring line failures. • Line tensions and environmental data shall be integrated into systems that record and relay all critical data in real time to the control room, Marine Terminal operator(s) and vessel operator(s).				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
• All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM (e.g. vessels are berthing within the MOTEMS compliant speed and angle requirements), and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing). • System shall include, but not be limited to, quick release hooks only (with load cells), site-specific current meter(s), site-specific anemometer(s), and visual and audible alarms that can support effective preset limits and shall be able to record and store monitoring data. • Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s). • Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide" Section 2.3.1.1, 2.3.1.2 and 2.3.1.4, are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives. • Install alternate technology that provides an equivalent level of protection. • All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis. The Marine Terminal is located in a high-velocity current area and currently has only limited devices to monitor mooring line strain and integrated environmental conditions. Updated MOTEMS Terminal Operating Limits (TOLs), including breasting and mooring, provide mooring requirements and operability limits that account for the conditions at the terminal. The upgrade to devices with monitoring capabilities can warn operators of the development of dangerous mooring situations, allowing time to take corrective action and minimize the potential for the parting of mooring lines, which can quickly escalate to the breaking of hose connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a petroleum product spill. Backed up by an alarm system,				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
real-time data monitoring and control room information would provide the Terminal Person-In-Charge with immediate knowledge of whether safe operating limits of the moorings are being exceeded. Mooring adjustments can be then made to reduce the risk of damage and accidental conditions. **Allision Avoidance Systems** • Provide and maintain Allision Avoidance Systems (AASs) at the Marine Terminal to prevent damage to the pier/wharf and/or vessel during docking and berthing operations. Integrate AASs with Tension Monitoring Systems such that all data collected are available in the Control Room and to Marine Terminal operator(s) at all times and vessel operator(s) during berthing operations. The AASs shall also be able to record and store monitoring data. • All systems data shall be required to be recorded and readily accessible to enable tasks such as: (1) verification that systems are routinely operated in compliance with the MM, and (2) post-event investigation and root-cause analysis (e.g. vessel allision during berthing). • Document procedures and training for systems use and communications between Marine Terminal and vessel operator(s). • Routine inspection, testing and maintenance of all equipment and systems in accordance with manufacturers' recommendations and necessity, as well as guidance provided by SIGTTO/OCIMF 2008 "Jetty Maintenance and Inspection Guide", are required to ensure safety and reliability. The inspections, testing, and maintenance will be performed by Phillips 66 or its designated representatives. • Velocity monitoring equipment is required to monitor reduced berthing velocities until permanent MOTEMS-compliant corrective actions are implemented. • The systems shall also be utilized to monitor for vessel motion (i.e. surge and sway) during breasting/mooring operations to ensure excessive surge and sway are not incurred. The Marine Terminal has a continuously manned marine interface operation monitoring all aspects of the marine interface. The Automatic Identification System is monitored through TerminalSmart and provides a record of vessel movements. Pursuant to the CSLC January 26, 2022 letter entitled Phillips 66 (P66) Rodeo Marine Terminal – Review of New September 2021				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
Mooring & Berthing Analyses and Terminal Operating Limits (TOLS), the single cone fenders shall not be used as the first point of contact during berthing operations. Therefore, all berthing operations shall utilize the double cone fenders. P66 shall incorporate TOL diagrams with landing point statements in the Terminal Information Booklet. For all vessels, a Phillips 66 Marine Advisor is in attendance and is in radio contact with the vessel master and pilot prior to berthing, reviewing initial contact point and then monitoring. Excessive surge or sway of vessels (motion parallel or perpendicular to the wharf, respectively), and/or passing vessel forces may result in sudden shifts/redistribution of mooring forces through the mooring lines. This can quickly escalate to the failure of mooring lines, breaking of loading arm connections, the breakaway of a vessel, and/or other unsafe mooring conditions that could ultimately lead to a spill. Monitoring these factors will ensure that all vessels can safely berth at the Marine Terminal and comply with the standards required in the MOTEMS.				
Transportation and Traffic				
Mitigation Measure TRA-1: Implement a Traffic Management Plan. Prior to issuance of grading and building permits, Phillips 66 shall submit a Traffic Management Plan for review and approval by the Contra Costa County Public Works Department. At a minimum the following shall be included: • The Traffic Management Plan shall be prepared in accordance with the most current California Manual on Uniform Traffic Control Devices, and will be subject to periodic review by the Contra Costa County Public Works Department throughout the life of all construction and demolition phases. • Truck drivers shall be notified of and required to use the most direct route between the site and the freeway; • All site ingress and egress shall occur only at the main driveways to the Project site; • Construction vehicles shall be monitored and controlled by flaggers; • If during periodic review the Contra Costa County Public Works Department, or the Department of Conservation and Development, determines the Traffic Management Plan requires modification, Phillips 66 shall revise the Traffic Management Plan to meet the	Prior to Contra Costa County Building Permit Issuance	Phillips 66	Contra Costa County Conservation and Development	

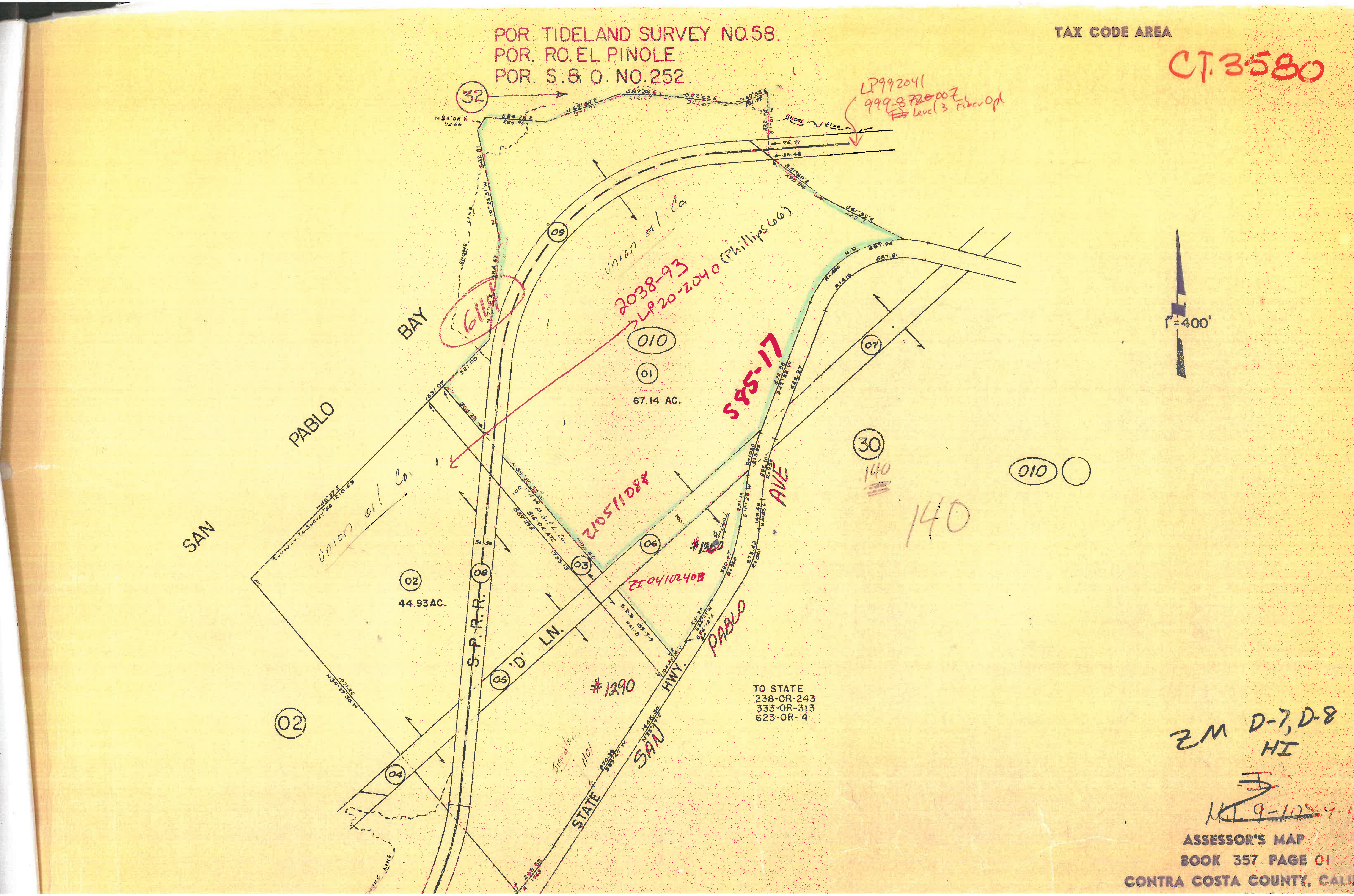
Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
specifications of Contra Costa County to address any identified issues. This may include such actions as traffic signal modifications, staggered work hours, or other measures deemed appropriate by the Public Works Department. • If required, Phillips 66 shall obtain the appropriate permits from Caltrans and the Contra Costa County Public Works Department for the movement of oversized or excessive load vehicles on state-administered highways or County maintained roads respectively.				
Tribal Cultural Resources				
Mitigation Measure TCR-1: Awareness Training • A consultant and construction worker tribal cultural resources awareness brochure and training program for all personnel involved in project implementation shall be developed by Phillips 66 in coordination with interested Native American Tribes (i.e. Wilton Rancheria). The brochure will be distributed and the training will be conducted in coordination with qualified cultural resources specialists and Native American Representatives and Monitors from culturally affiliated Native American Tribes before any stages of project implementation and construction activities begin on the Project site. The program will include relevant information regarding sensitive tribal cultural resources, including applicable regulations, protocols for avoidance, and consequences of violating state laws and regulations. The worker cultural resources awareness program will also describe appropriate avoidance and minimization measures for resources that have the potential to be located on the Project site and will outline what to do and whom to contact if any potential archaeological resources or artifacts are encountered. The program will also underscore the requirement for confidentiality and culturally-appropriate treatment of any find of significance to Native Americans and behaviors, consistent with Native American Tribal values.	Prior to Contra Costa County Building Permit Issuance; ongoing	Phillips 66	Contra Costa County Conservation and Development	
Mitigation Measure TCR -2: Monitoring To minimize the potential for destruction of or damage to existing or previously undiscovered burials, archaeological and tribal cultural resources and to identify any such resources at the earliest possible time during	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development	

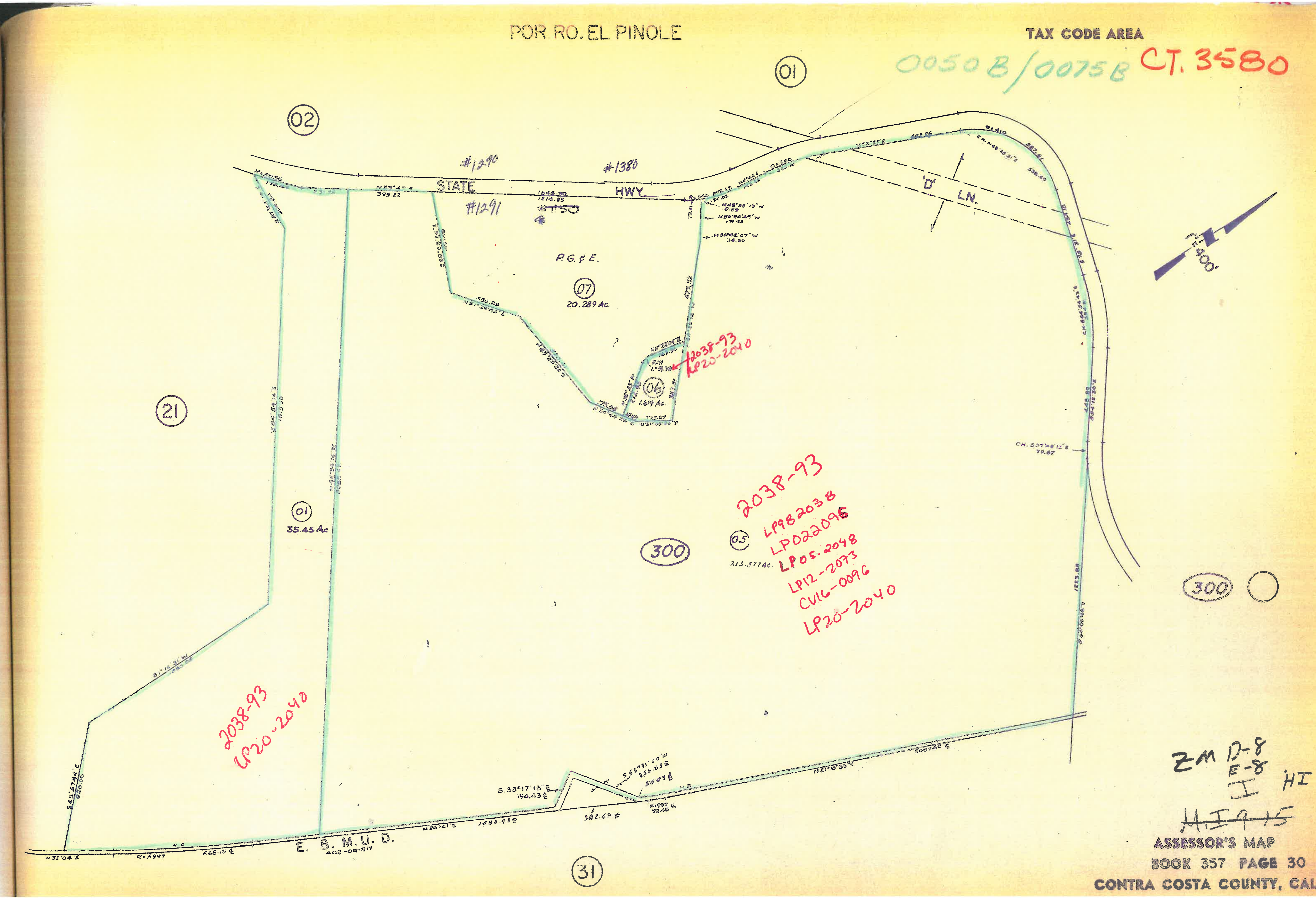
Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
project-related earthmoving activities, Phillips 66 and its construction contractor(s) will implement the following measures: • Paid Native American monitors from culturally affiliated Native American Tribes will be invited to monitor the vegetation grubbing, stripping, grading or other ground-disturbing activities in the project area to determine the presence or absence of any cultural resources. Native American representatives from cultural affiliated Native American Tribes act as a representative of their Tribal government and shall be consulted before any cultural studies or ground-disturbing activities begin. • Native American representatives and Native American monitors have the authority to identify sites or objects of significance to Native Americans and to request that work be stopped, diverted or slowed if such sites or objects are identified within the direct impact area. Only a Native American representative can recommend appropriate treatment of such sites or objects. • If buried cultural resources, such as chipped or ground stone, historic debris, building foundations, or bone, are discovered during ground-disturbing activities, work will stop in that area and within 100 feet of the find until an archaeologist who meets the Secretary of the Interior's qualification standards can assess the significance of the find and, if necessary, develop appropriate treatment measures in consultation with the California Department of Transportation, the State Historic Preservation Office, and other appropriate agencies. Appropriate treatment measures may include development of avoidance or protection methods, archaeological excavations to recover important information about the resource, research, or other actions determined during consultation. • In accordance with the California Health and Safety Code, if human remains are uncovered during ground disturbing activities, the construction contractor or the County, or both, shall immediately halt potentially damaging excavation in the area of the burial and notify the County coroner and a qualified professional archaeologist to determine the nature of the remains. The coroner shall examine all discoveries of human remains within 48 hours of receiving notice of a discovery on private or state lands, in accordance with Section 7050(b) of the Health and Safety Code. If the coroner determines				

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
that the remains are those of a Native American, they shall contact the NAHC by phone within 24 hours of making that determination (Health and Safety Code Section 7050[c]). After the coroner's findings are presented, the County, the archaeologist, and the NAHC-designated MLD shall determine the ultimate treatment and disposition of the remains and take appropriate steps to ensure that additional human interments are not disturbed.				
Mitigation Measure TCR -3: Inadvertent Discoveries • Phillips 66 shall develop a standard operating procedure, or ensure any existing procedure, to include points of contact, timeline and schedule for the project so all possible damages can be avoided or alternatives and cumulative impacts properly accessed. • If potential tribal cultural resources, archaeological resources, other cultural resources, articulated, or disarticulated human remains are discovered by Native American Representatives or Monitors from interested Native American Tribes, qualified cultural resources specialists or other Project personnel during construction activities, work will cease in the immediate vicinity of the find (based on the apparent distribution of cultural resources), whether or not a Native American Monitor from an interested Native American Tribe is present. A qualified cultural resources specialist and Native American Representatives and Monitors from culturally affiliated Native American Tribes will assess the significance of the find and make recommendations for further evaluation and treatment as necessary. These recommendations will be documented in the project record. For any recommendations made by interested Native American Tribes which are not implemented, a justification for why the recommendation was not followed will be provided in the project record. • If adverse impacts to tribal cultural resources, unique archeology, or other cultural resources occurs, then consultation with Wilton Rancheria regarding mitigation contained in the Public Resources Code sections 21084.3(a) and (b) and CEQA Guidelines section 15370 should occur, in order to coordinate for compensation for the impact by replacing or providing substitute resources or environments.	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
• If cultural resources are recovered on State lands, submerged or tidal lands, all work within 100 feet of the find shall be halted and Phillips 66 shall consult with the California State Lands Commission.				
Mitigation Measure TCR-4: Avoidance and Preservation Avoidance and preservation in place is the preferred manner of mitigating impacts to tribal cultural resources and shall be accomplished by several means, including: • Planning construction to avoid tribal cultural resources, archaeological sites and/ or other resources; incorporating sites within parks, green-space or other open space; covering archaeological sites; deeding a site to a permanent conservation easement; or other preservation and protection methods agreeable to consulting parties and regulatory authorities with jurisdiction over the activity. Recommendations for avoidance of cultural resources will be reviewed by the CEQA lead agency representative, interested Native American Tribes and the appropriate agencies, in light of factors such as costs, logistics, feasibility, design, technology and social, cultural and environmental considerations, and the extent to which avoidance is consistent with project objectives. Avoidance and design alternatives may include realignment within the project area to avoid cultural resources, modification of the design to eliminate or reduce impacts to cultural resources or modification or realignment to avoid highly significant features within a cultural resource. Native American Representatives from interested Native American Tribes will be allowed to review and comment on these analyses and shall have the opportunity to meet with the CEQA lead agency representative and its representatives who have technical expertise to identify and recommend feasible avoidance and design alternatives, so that appropriate and feasible avoidance and design alternatives can be identified. • If the resource can be avoided, the construction contractor(s), with paid Native American monitors from culturally affiliated Native American Tribes present, will install protective fencing outside the site boundary, including a buffer area, before construction restarts. The construction contractor(s) will maintain the protective fencing throughout construction to avoid the site during all remaining	During construction and demolition	Phillips 66	Contra Costa County Conservation and Development	

Mitigation Measure	Implementation Timing	Implementation Responsibility	Verification Responsibility	Compliance Verification Date
phases of construction. The area will be demarcated as an "Environmentally Sensitive Area." Native American representatives from interested Native American Tribes and the CEQA lead agency representative will also consult to develop measures for long term management of the resource and routine operation and maintenance within culturally sensitive areas that retain resource integrity, including tribal cultural integrity, and including archaeological material, Traditional Cultural Properties and cultural landscapes, in accordance with state and federal guidance including National Register Bulletin 30 (Guidelines for Evaluating and Documenting Rural Historic Landscapes), Bulletin 36 (Guidelines for Evaluating and Registering Archaeological Properties), and Bulletin 38 (Guidelines for Evaluating and Documenting Traditional Cultural Properties); National Park Service Preservation Brief 36 (Protecting Cultural Landscapes: Planning, Treatment and Management of Historic Landscapes) and using the Advisory Council on Historic Preservation's Native American Traditional Cultural Landscapes Action Plan for further guidance. Use of temporary and permanent forms of protective fencing will be determined in consultation with Native American representatives from interested Native American Tribes.				


POR. TIDELAND SURVEY NO.58.
POR. RO. EL PINOLE
POR. S. & O. NO. 252.
TAX CODE AREA
CT. 3580
LP992041
999-872-007
Level 3 Fiber Opt
SAN PABLO BAY
Union oil Co.
2038-93
LP20-2040 (Phillips 66)
010
01
67.14 AC.
S85-17
6114
09
08
07
06
05
04
03
02
44.93 AC.
30
140
010
1" = 400'
S.P.R.R.
'D' LN.
2105111088
ZI0410240B
#1380
#1290
SAN PABLO AVE
STATE HWY.
TO STATE
238-OR-243
333-OR-313
623-OR-4
ZM D-7, D-8
HI
ASSESSOR'S MAP
BOOK 357 PAGE 01
CONTRA COSTA COUNTY, CALIF.



POR RO. EL PINOLE
TAX CODE AREA
0050B/0075B
CT. 3580
01
02
#1290
#1380
STATE
HWY.
#1291
'D' LN.
1" = 400'
P.G.& E.
07
20.289 Ac.
06
1.619 Ac.
2038-93
LP20-2040
21
01
35.45 Ac.
300
05
213.577 Ac.
2038-93
LP982038
LP022096
LP05-2048
LP12-2073
CV16-0096
LP20-2040
2038-93
LP20-2040
300
E. B. M. U. D.
31
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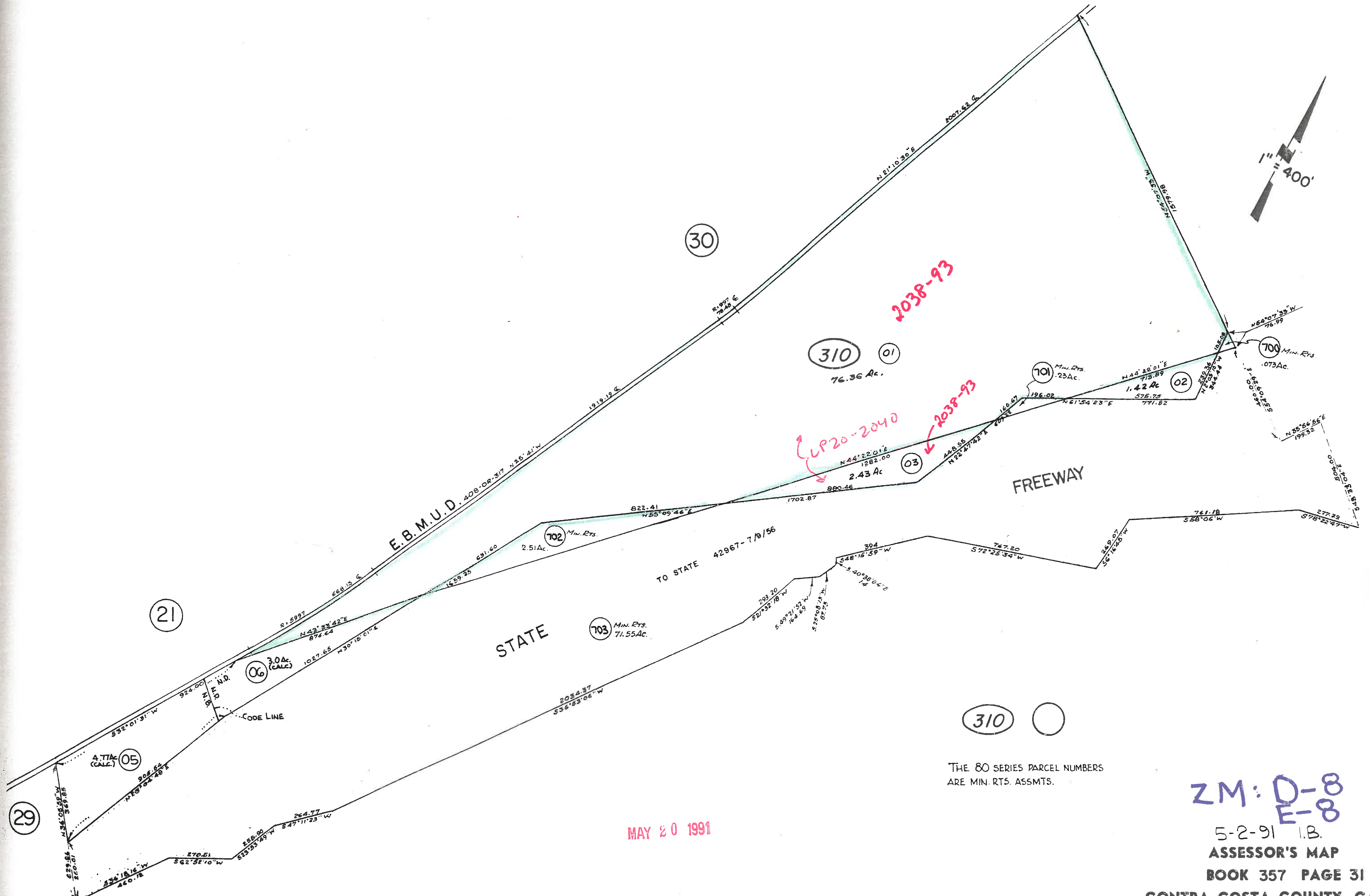
ASSESSOR'S MAP
BOOK 357 PAGE 30
CONTRA COSTA COUNTY, CALIF

POR. RO. EL PINOLE

TAX CODE AREA CT. 3580



THE 80 SERIES PARCEL NUMBERS ARE MIN. RTS. ASSMTS.

MAY 20 1991

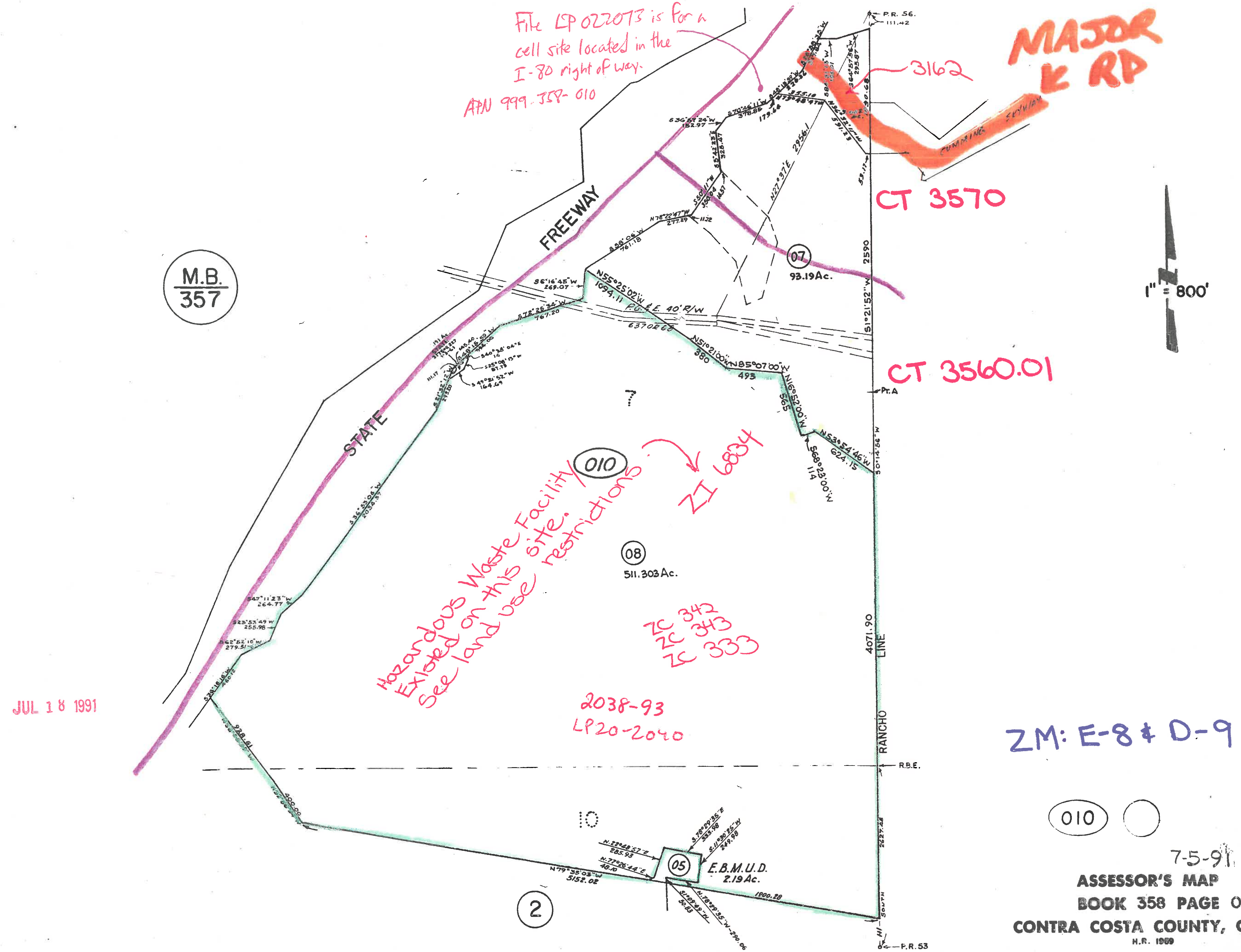
ZM: D-8 E-8

5-2-91 I.B.

ASSESSOR'S MAP
BOOK 357 PAGE 31
CONTRA COSTA COUNTY, CALIF.

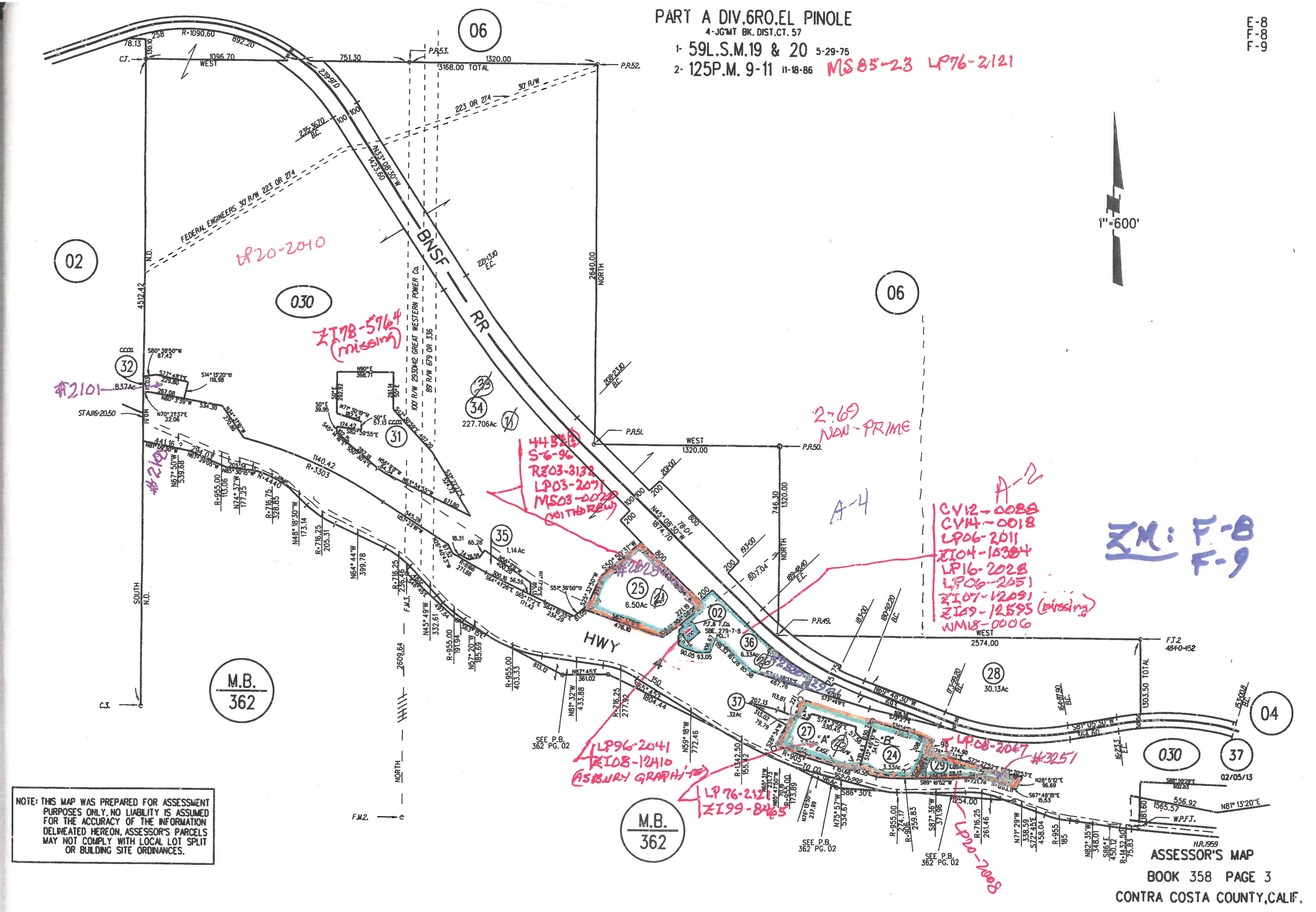
1958 HR

POR. DIV. 7&10 RO. EL PINOLE - 3 JG'MT. BK. DIST. CT. 274

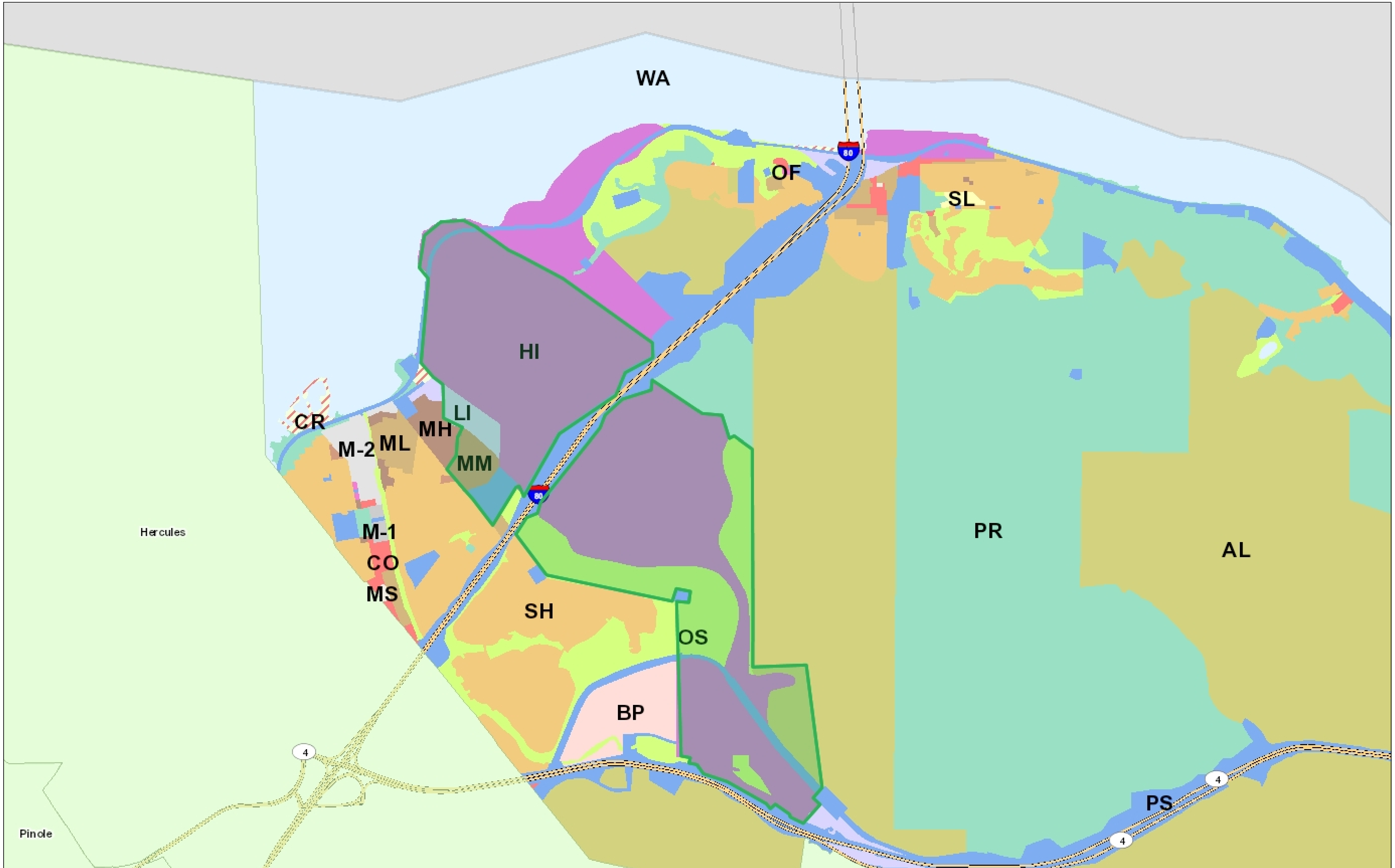


7-5-91

ASSESSOR'S MAP
BOOK 358 PAGE 01
CONTRA COSTA COUNTY, CALIF.
H.R. 1969


PART A DIV.6RO.EL PINOLE
4-JG'MT BK. DIST.CT. 57
1- 59L.S.M.19 & 20 5-29-75
2- 125P.M. 9-11 11-18-86
MS 85-23 LP76-2121
E-8
F-8
F-9
1"=600'
BNSF RR
HWY
FEDERAL ENGINEERS 30' R/W 223 OR 274
100' R/W 2930 42 GREAT WESTERN POWER Co.
LP20-2010
ZI78-5764 (missing)
#2101
2-69 NON-PRIME
A-4
A-2
ZM: F-8 F-9
CV12-0088
CV14-0018
LP06-2011
ZI04-15384
LP16-2028
LP06-2051
ZI07-12091
ZI09-12595 (missing)
WM18-0006
LP96-2041
ZI08-12410
(ASBURY GRAPHITE)
LP76-2121
ZI99-8465
LP08-2067
#3251
LP20-2008
030
34 227.706Ac
25 6.50Ac
28 30.13Ac
M.B. 362
NOTE: THIS MAP WAS PREPARED FOR ASSESSMENT PURPOSES ONLY. NO LIABILITY IS ASSUMED FOR THE ACCURACY OF THE INFORMATION DELINEATED HEREON. ASSESSOR'S PARCELS MAY NOT COMPLY WITH LOCAL LOT SPLIT OR BUILDING SITE ORDINANCES.
02/05/13
ASSESSOR'S MAP
BOOK 358 PAGE 3
CONTRA COSTA COUNTY, CALIF.

General Plan: HI, OS, LI, MM



Legend

- City Boundary
- Unincorporated
- Highways
- Highways Bay Area
- General Plan
  - SV (Single Family Residential - Ver
  - SL (Single Family Residential - Low
  - SM (Single Family Residential - Me
  - SH (Single Family Residential - Hig
  - ML (Multiple Family Residential - Lc
  - MM (Multiple Family Residential - M
  - MH (Multiple Family Residential - H
  - MV (Multiple Family Residential - V
  - MS (Multiple Family Residential - V
  - CC (Congregate Care/Senior Housi
  - MO (Mobile Home)
  - M-1 (Parker Avenue Mixed Use)
  - M-2 (Downtown/Waterfront Rodeo I
  - M-3 (Pleasant Hill BART Mixed Use
  - M-4 (Willow Pass Road Mixed Use)
  - M-5 (Willow Pass Road Commercia
  - M-6 (Bay Point Residential Mixed U
  - M-7 (Pittsburg/Bay Point BART Sta
  - M-8 (Dougherty Valley Village Cent
  - M-9 (Montalvin Manor Mixed Use)
  - M-10 (Willow Pass Business Park M
  - M-11 (Appian Way Mixed Use)
  - M-12 (Triangle Area Mixed Use)
  - M-13 (San Pablo Dam Road Mixed
  - M-14 (Heritage Mixed Use)
  - CO (Commercial)
  - OF (Office)
  - BP (Business Park)
  - LI (Light Industry)
  - HI (Heavy Industry)
  - AL, OIBA (Agricultural Lands & Off
  - CR (Commercial Recreation)
  - ACO (Airport Commercial)
  - LF (Landfill)

1: 36,112

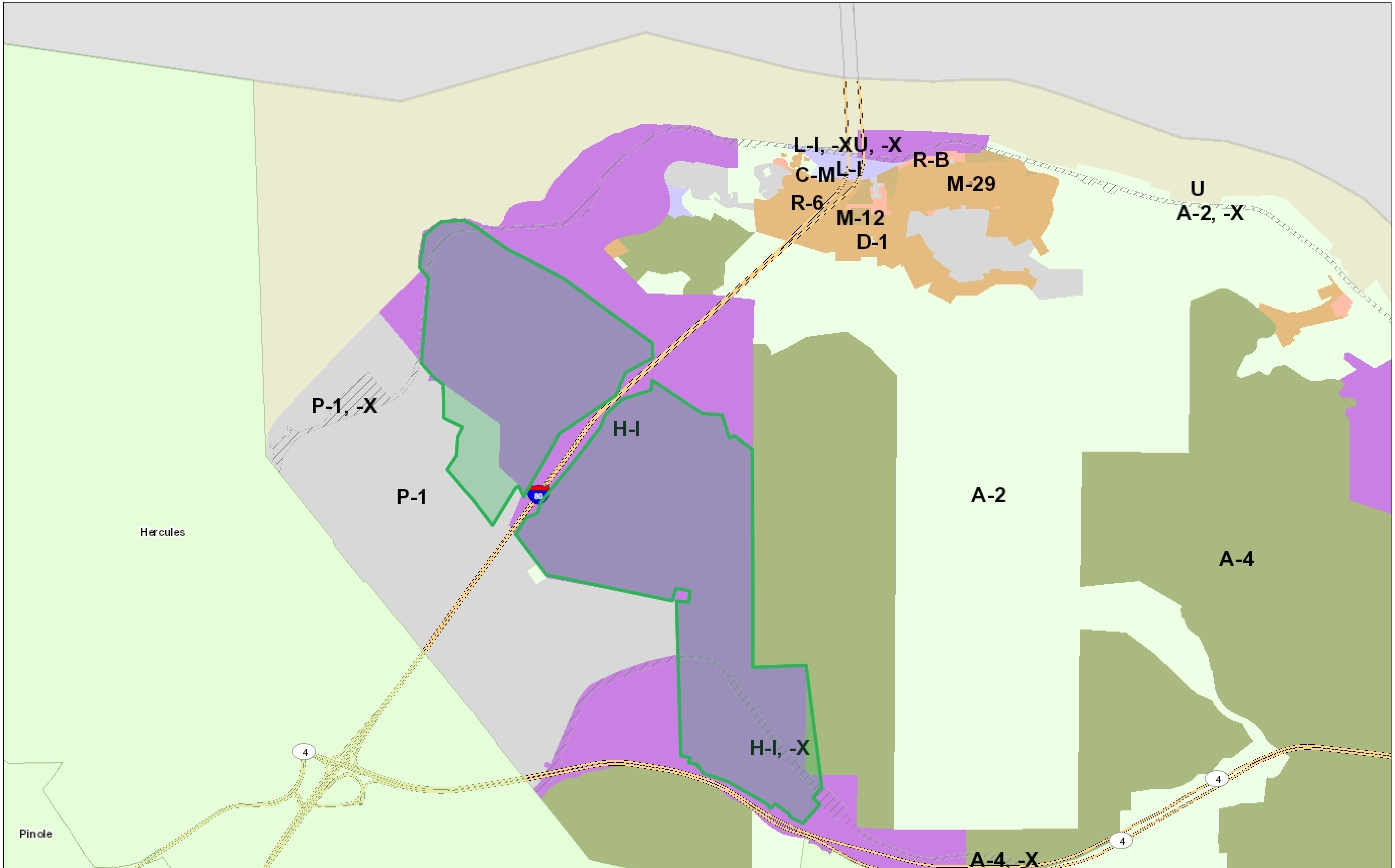
1.1 0 0.57 1.1 Miles

WGS_1984_Web_Mercator_Auxiliary_Sphere

Notes

Phillips 66 -approximate area of all parcels

Zoning: H-I, P-1, -X



Legend

- City Boundary
- Unincorporated
- Highways
- Highways Bay Area
- Zoning
  - R-6 (Single Family Residential)
  - R-6 -FH (Single Family Residential Combining District)
  - R-6, -FH -UE (Single Family Resid Urban Farm Animal Exclusion Com
  - R-6 -SD-1 (Single Family Resident Hillside Development Combining Di
  - R-6 -TOV -K (Single Family Reside View Ordinance and Kensington Cc
  - R-6, -UE (Single Family Residential Exclusion Combining District)
  - R-6 -X (Single Family Residential - Combining District)
  - R-7 (Single Family Residential)
  - R-7 -X (Single Family Residential - Combining District)
  - R-10 (Single Family Residential)
  - R-10, -UE (Single Family Residenti Exclusion Combining District)
  - R-12 (Single Family Residential)
  - R-15 (Single Family Residential)
  - R-20 (Single Family Residential)
  - R-20, -UE (Single Family Residenti Exclusion Combining District)
  - R-40 (Single Family Residential)
  - R-40 -FH (Single Family Residenti Combining District)
  - R-40, -FH -UE (Single Family Resic Urban Farm Animal Exclusion Com
  - R-40, -UE (Single Family Residenti Exclusion Combining District)
  - R-65 (Single Family Residential)
  - R-100 (Single Family Residential)
  - D-1 (Two Family Residential)
  - D-1 -T (Two Family Residential - Tr District)
  - D-1, -UE (Planned Unit - Urban Far Combining District)
  - M-12 (Multiple Family Residential)
  - M-12 -FH (Multiple Family Resident Combining District)
  - M-17 (Multiple Family Residential)
  - M-29 (Multiple Family Residential)

1: 36,112

1.1 0 0.57 1.1 Miles

WGS_1984_Web_Mercator_Auxiliary_Sphere

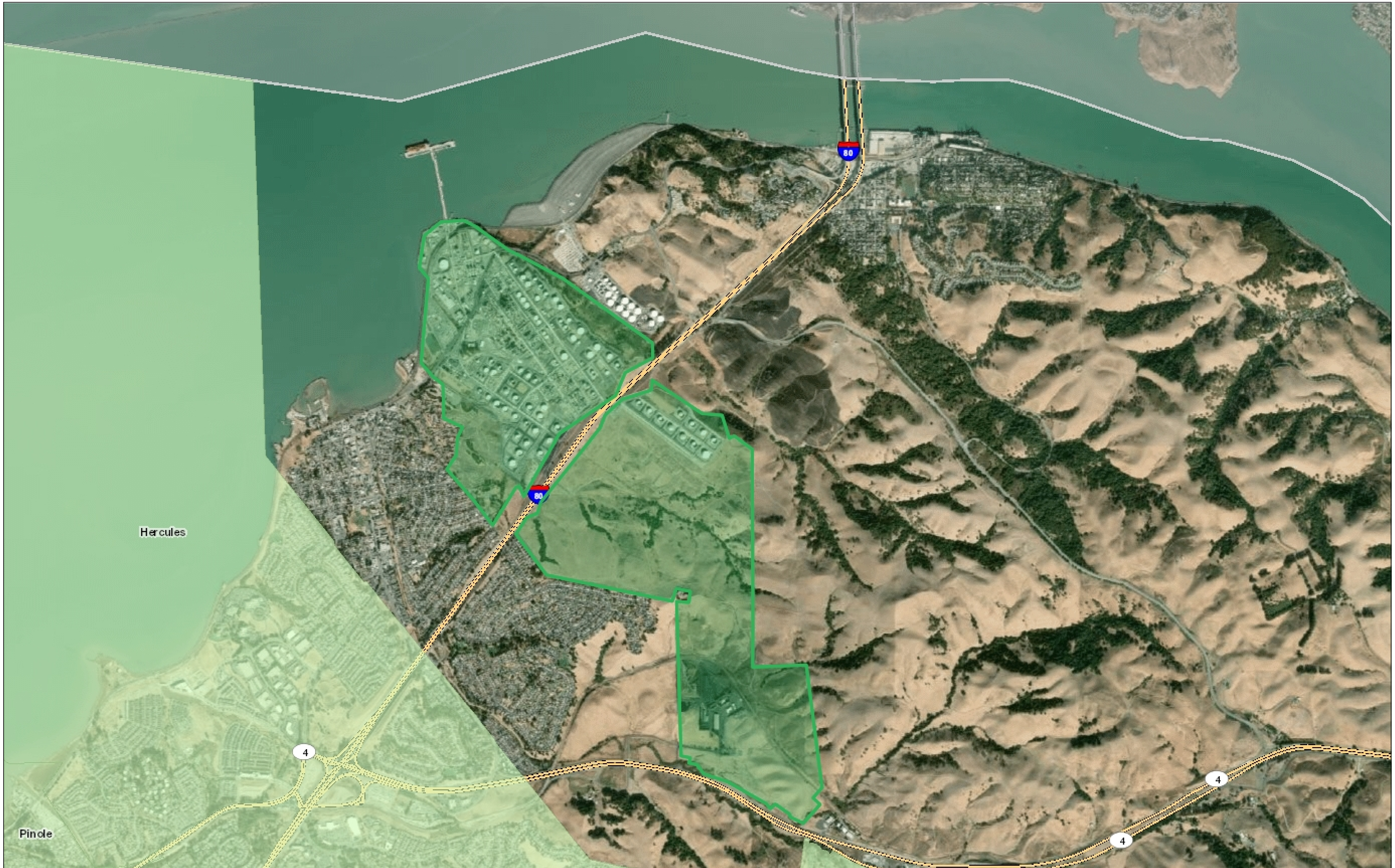
This map is a user generated static output from an Internet mapping site and is for reference only. Data layers that appear on this map may or may not be accurate, current, or otherwise reliable.

THIS MAP IS NOT TO BE USED FOR NAVIGATION

Notes

Phillips 66 -approximate area of all parcels

Aerial View



Legend

- City Boundary
- Unincorporated
- Highways
- Highways Bay Area
- County Boundary
- Bay Area Counties
- World Imagery
- Low Resolution 15m Imagery
- High Resolution 60cm Imagery
- High Resolution 30cm Imagery
- Citations

1: 36,112

1.1 0 0.57 1.1 Miles

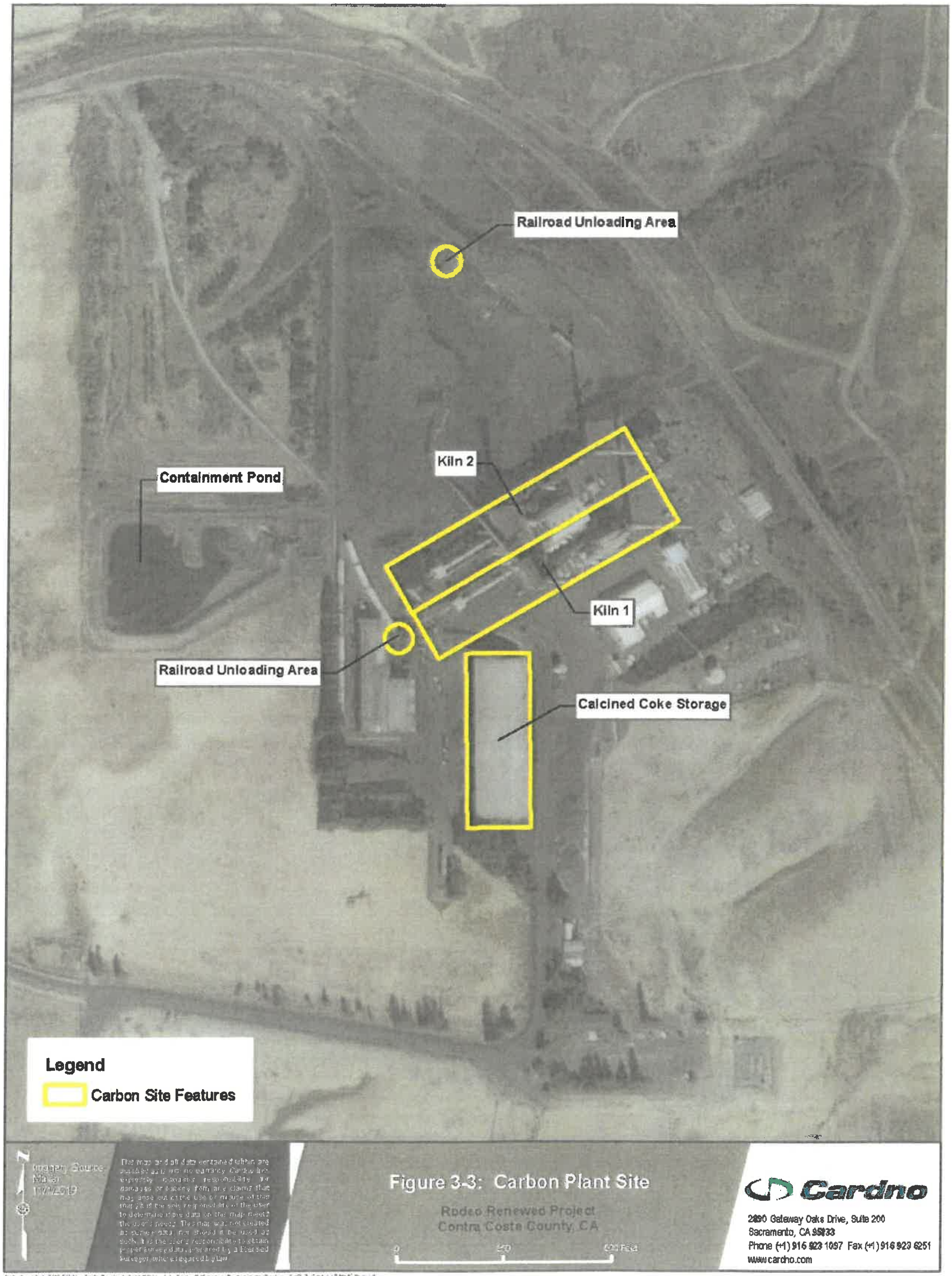
WGS_1984_Web_Mercator_Auxiliary_Sphere

This map is a user generated static output from an Internet mapping site and is for reference only. Data layers that appear on this map may or may not be accurate, current, or otherwise reliable.
THIS MAP IS NOT TO BE USED FOR NAVIGATION

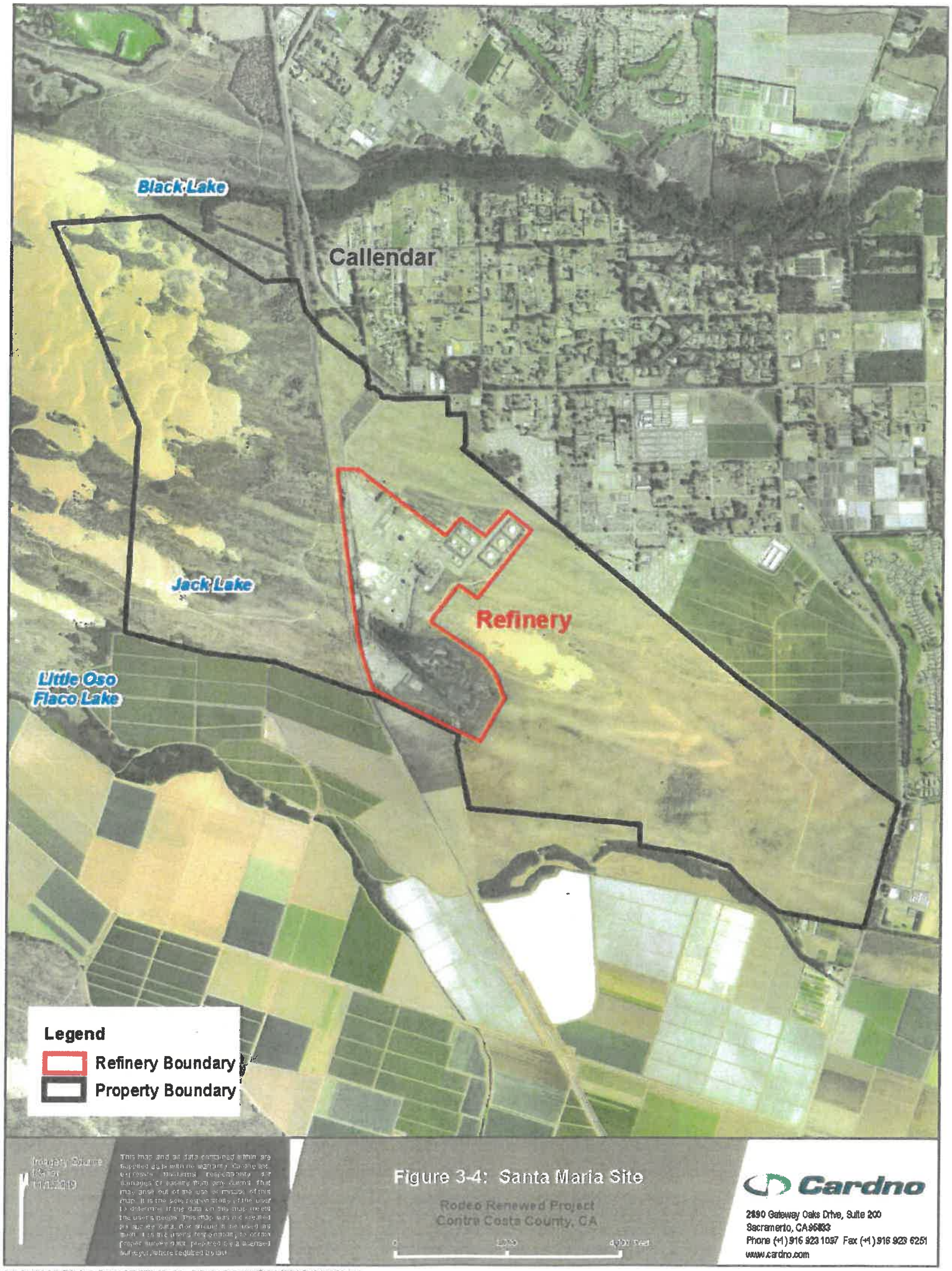
Notes

Phillips 66 -approximate area of all parcels

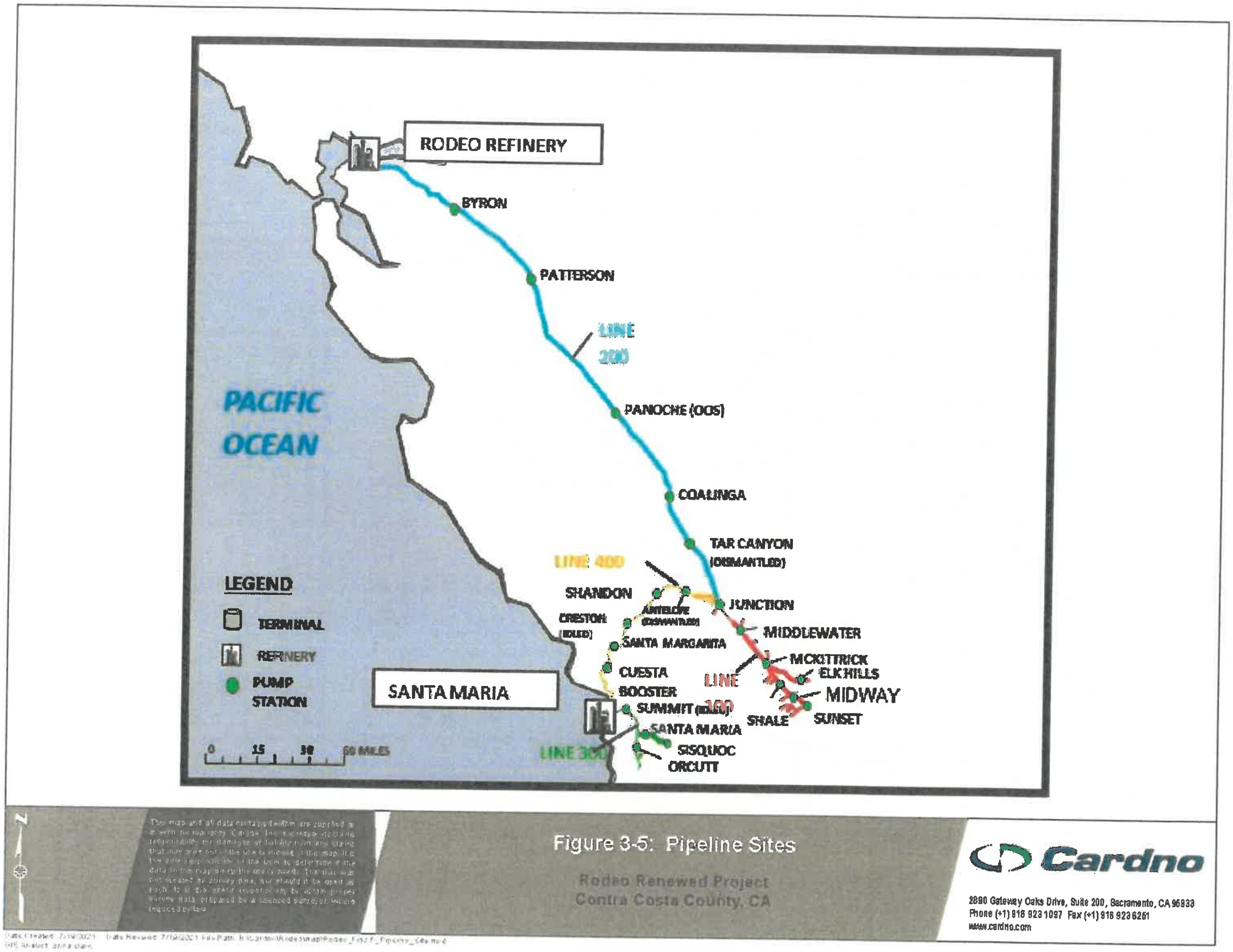
Rodeo Site **1380 San Pablo Ave, Rodeo, CA 94572**



Carbon Plant Site 2101 Franklin Canyon Rd, Rodeo, CA 94572



Santa Maria Site   2555 Willow Rd, Arroyo Grande, CA 93420



Pipeline Sites

PHILLIPS 66 RODEO RENEWED PROJECT

(County File# CDLP20-02040)

CONTRA COSTA COUNTY DEPARTMENT OF CONSERVATION AND DEVELOPMENT

PRESENTED BY:
GARY KUPP, SENIOR PLANNER

PROJECT SITE LOCATIONS

- Contra Costa County (Rodeo Refinery)
- San Luis Obispo County (Santa Maria Refinery)
- Pipelines Sites (by County):

  = Kern
  = Kings
  = Fresno
  = Merced
  = Alameda
  = Stanislaus
  = San Joaquin
  = Santa Barbara

RODEO REFINERY SITE

1380 SAN PABLO AVENUE

RODEO, CA 94572

CARBON PLANT SITE

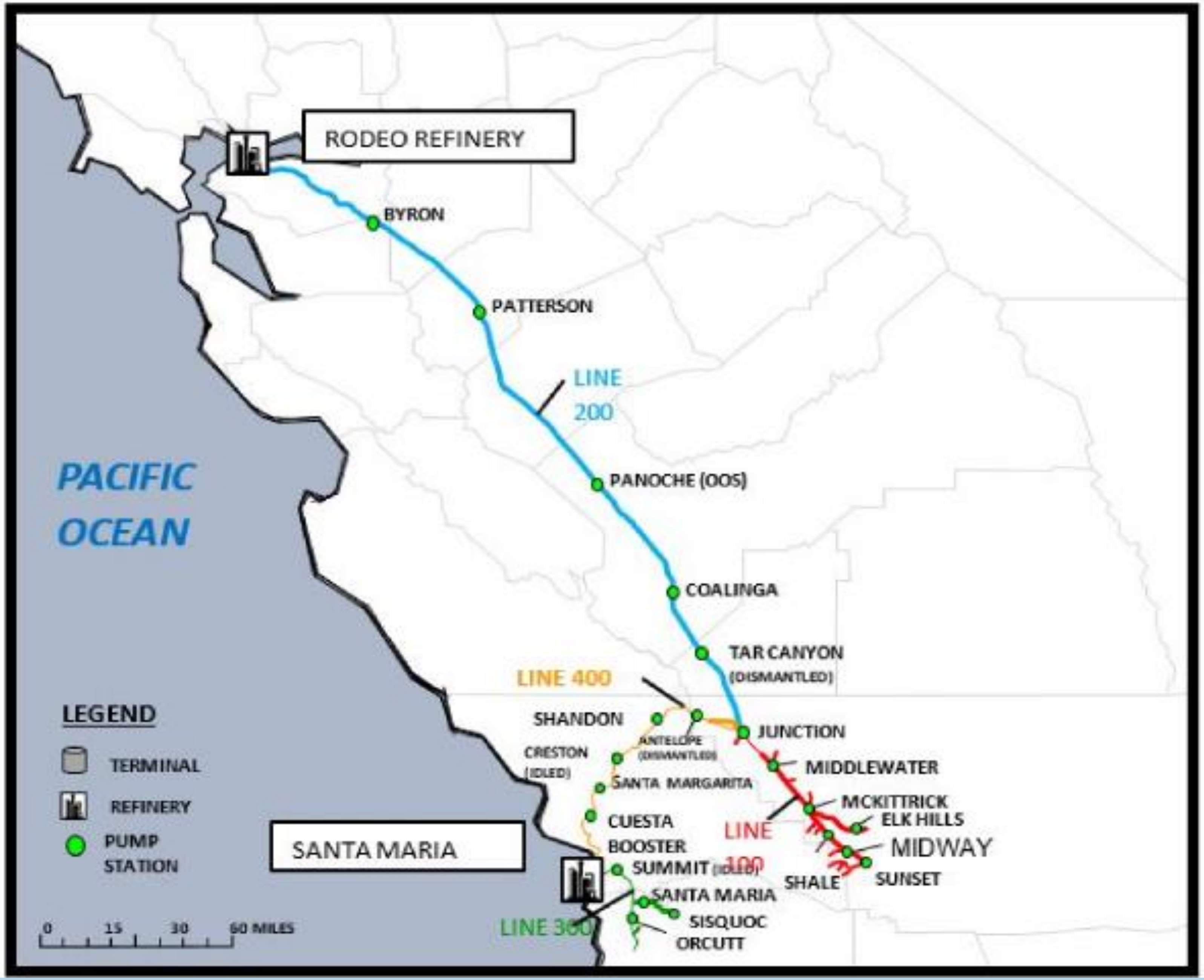
2101 FRANKLIN CANYON ROAD

RODEO, CA 94572

SANTA MARIA REFINERY SITE

2555 WILLOW ROAD

ARROYO GRANDE, CA 93420



PIPELINE SITES

4 PIPELINES IN THE CENTRAL VALLEY RUNNING BETWEEN THE RODEO AND SANTA MARIA REFINERIES

PROJECT MILESTONES

- <u>Application</u>: Filed on 8/13/2020
- <u>CEQA Notice of Preparation</u>: Issued 12/21/2020
- <u>Draft EIR</u>: 60-Day Circulation 10/18/2021 – 12/17/2021
- <u>Final EIR</u>: March 2022 – Responses to Comments on Draft EIR
- <u>County Planning Commission Hearing</u>: 3/30/2022

PROJECT PURPOSE

Phillips 66 intends to modify and repurpose the facility for the processing of renewable feedstocks into renewable fuels, including renewable diesel.

RENEWABLE FEEDSTOCKS

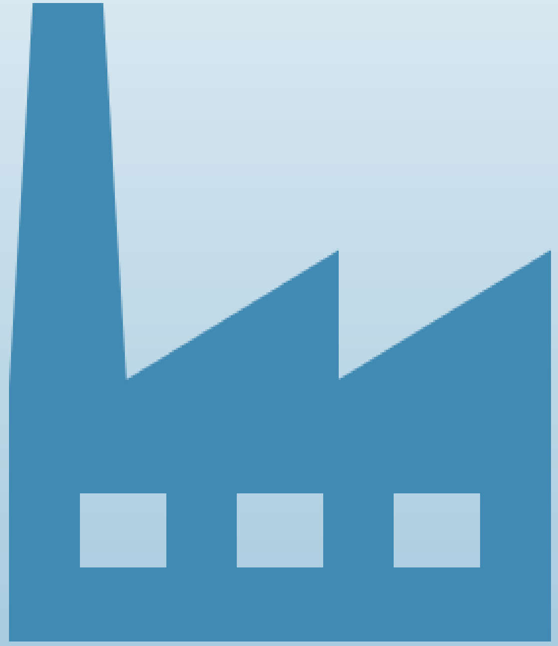
The anticipated renewable feedstocks processed at the facility would include, but not be limited to, the following:

- Used Cooking Oil,
- Grease
- Tallow (animal fat),
- Inedible Corn Oil,
- Canola Oil,
- Soybean Oil,
- Other Vegetable-Based Oils.

REFINERY MODIFICATIONS

Under the project, components to be permanently shut down and demolished include:

- **Santa Maria Refinery**
- **Rodeo Carbon Plant**
- **Pipeline Sites**



REFINERY MODIFICATIONS CONT.

(NEW EQUIPMENT)

- **<u>Pre-Treatment Unit (PTU)</u>: The new PTU would be constructed on the site of three existing storage tanks. New equipment would be added to decontaminate and condition the renewable feedstocks prior to processing.**
- **<u>Sulfur Treatment Unit (STU)</u>: The new STU would include a thermal oxidizer, waste heat boiler, caustic scrubber tower, and fresh and spent caustic tanks to control ammonia and hydrogen sulfide off-gases.**

REFINERY MODIFICATIONS CONT.

(MODIFIED EXISTING UNITS)

- <u>U240 Hydrocracker</u>: Replace two existing reactor vessels; replace and modify existing heat exchangers; add new process surge vessel, storage tanks, and feed filters.
- <u>U246 Hydrocracker</u>: Replace and modify existing heat exchangers; add new exchangers and new storage tanks, process pump, and feed filters.
- <u>U110 Hydrogen Plant</u>: Install new piping, fuel gas cooler, and control valve station to process renewable fuel gas at to produce renewable hydrogen.
- <u>Rail Butane Loading Rack</u>: Convert the existing butane rail loading stations to receive renewable feedstock by rail.

PROJECT BASELINE

Section 15125 of the California Environmental Quality Act requires that an Environmental Impact Report must include a description of the physical environmental conditions in the vicinity of the project to provide an accurate baseline setting.

- **Generally, the project baseline should describe physical environmental conditions as they exist at the time the Notice of Preparation is published; ALTHOUGH,**

- **Where existing conditions change or fluctuate over time, and as necessary to provide the most accurate picture of the project's impacts, CEQA also allows the existing baseline conditions for a project to be defined by referencing historic conditions that are supported with substantial evidence.**

BASELINE: REFINERY OPERATIONS

In light of the 2020 COVID-19 pandemic and its effects on the economy of the San Francisco Bay Area and the northern California region, 2019 was selected for the project baseline for refinery process operations.

Table 3-5. Historical Throughput for Rodeo Refinery Facilities (Refinery and Carbon Plant Combined)

Type	Units	2016	2017	2018	2019	2020
Feedstocks	MBPD	117	124	125	120	104
Products	MBPD	118	126	127	121	105

Note: MBPD = thousand barrels per day

BASELINE: MARINE VESSEL ACTIVITY

- A 3-year average baseline period was used for marine vessel activity (2017 through 2019)
- 2019 had unusually high vessel traffic, which if used, would over-state baseline conditions.

Annual Vessel Traffic at Rodeo Refinery Marine Terminal							
Vessel Class	2016	2017	2018	2019	2020	3-year Average (2017-2019)	3-year Average (2018-2020)
Barges	83	63	73	135	86	90	98
Tankers	81	82	76	84	63	81	74
Total Visits	164	145	149	219	149	170	172

RENEWABLE PRODUCTION LEVELS

- Up to 80,000 barrels/day (bpd) of renewable feedstocks would be received at the Rodeo refinery and would be processed in the proposed Pre-Treatment Unit.
- Once operational, the Rodeo refinery would supply up to 107,000 bpd of fuel, both renewable fuels (67,000 bpd) and petroleum-based transportation fuels or gasoline (40,000 bpd).
- Of the 67,000 bpd of renewable fuels that would be produced, 55,000 bpd would occur as a result of the project.
- The Rodeo Refinery could receive, blend, and ship up to 40,000 bpd of gasoline and gasoline blendstocks under the project.

MARINE TERMINAL

- The project also proposes a temporary increase in deliveries of crude oil and gas oil feedstocks by tanker vessel during the transitional period prior to project start-up.
- The increase would not increase the amount of crude and gas oil that can currently be processed at the Rodeo refinery.

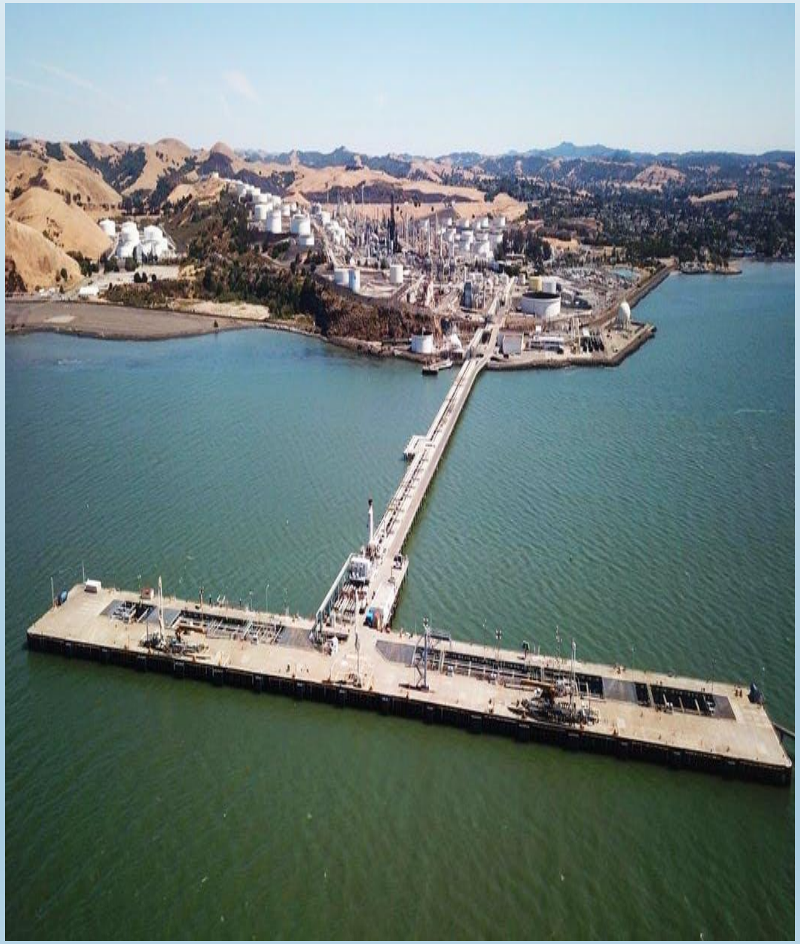


Table 3-4. Marine Terminal Traffic and Crude/Gas Oil Deliveries during Transitional Phase

Activity	Baseline	Transitional Phase
Crude and Gas Oil Received through Marine Terminal (1,000 barrels/day 12-month average)	35	85
Pipeline Crude Received (1,000 barrels/day 12-month average)	70	0
Tanker Vessels (calls/year)	80	96
Barges (calls/year)	90	92

All-SOURCE REDUCTIONS FOR CRITERIA POLLUTANTS (PERCENT)

Source	Emissions (tons/year)					
	VOC	NO_x	PM_{10} [a]	$PM_{2.5}$ [a]	SO_2	CO
Rodeo Facility Project Emissions						
Ocean-going Vessels and Harbor Craft	16	266	7	7	11	87
Trucks	0.03	2.38	2.1	0.37	0.02	0.19
Rail	0.18	4.79	0.11	0.1	0.08	1.38
Facility Stationary Sources	111	210	71	69	295	51
Total Operational	127	483	81	76	307	140
Air Liquide H_2 Plant	1	22	5	5	0	1
Total Operational with Air Liquide	129	505	85	81	307	141
Percent Reductions	**0%**	**-33%**	**-19%**	**-17%**	**-79%**	**-7%**

All-SOURCE REDUCTIONS FOR GREENHOUSE GASSES (PERCENT)

Source	Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Renewed Project Emissions				
Ocean Going Vessels and Harbor Craft	26,195	0.28	1.53	26,657
Rail	8,119	0.64	0.2	8,195
Trucks	2,720	0	0.43	2,847
Facility Stationary Sources	1,069,772	84.51	10.79	1,075,100
Electricity	1,180	0.41	0.09	2,889
Total Operational	1,109,661	85.84	13.04	1,115,689
Air Liquide H_2 Plant	1,031,689			1,031,689
Total Operational with Air Liquide	2,141,350	85.84	13.04	2,147,378
Percent Reductions	**-8.7%**	**-23.4%**	**-18.5%**	**-8.7%**

APPEALS

The Planning Commission's March 30 decision to approve the project received 3 appeals:

- **Natural Resources Defense Council, et. al. – 4/7/2022**
- **Mr. Charles Davidson – 4/11/2022**
- **Crockett Community Foundation – 4/11/2022**

NATURAL RESOURECES DEFENSE COUNCIL, et. al.

Joint Appeal Filed On April 7, 2022, Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County

MAJOR APPEAL POINTS

The Appeal presents the following general issues:

Adequacy of FEIR to Address Impacts and Respond to Comments;

Concern with Unit 250 in the Project Analysis;

Adequacy of Response to Public Comments;

Findings Concerning Choice of Alternatives and Throughput Volumes;

Introduction of “New” Information;

Accuracy of the Statement of Overriding Considerations; and

Provisions Regarding Site Cleanup.

Adequacy of FEIR to Address Impacts and Respond to Comments

The following issues are addressed within the first appeal point:

(a) Project description

(b) Baseline

(c) Operational upsets

(d) Food system oil consumption

(e) Odor mitigation plan

(f) Cumulative impacts

(g) California climate pathways

(h) Transportation risk impacts

Mr. Charles Davidson

The Appeal presents three general issues:

Hydrogen Use
Climate Pathways and the LCFS
Soybean as “default principal feedstock”

Crockett Community Foundation

Appellants contend that “Terms of proposed Community Benefits Agreement were not sufficiently defined.”

CONCLUSION

The proposed Phillips 66 Rodeo Renewed Project, as conditioned would provide the following benefits:

- Consistent with the General Plan and the Heavy Industrial Zoning.
- Reductions in Greenhouse Gas Emissions.
- Reductions in Criteria Pollutant Emissions.
- Demolition of the Carbon Plant and the Santa Maria Refinery.
- Retains Current Employment Levels.
- Reductions in Energy and Natural Gas Usage.

CONCLUSION CONT.

<u>STAFF RECOMMENDATIONS</u>

1. OPEN the public hearing on an appeal of a Planning Commission decision to approve a land use permit for the Phillips 66 Rodeo Renewed Project at 1380 San Pablo Avenue in Rodeo and other project locations. (County File# CDLP20-02040), RECEIVE testimony, and CLOSE the public hearing.
2. CERTIFY that the Environmental Impact Report (EIR) for the Phillips 66 Rodeo Renewed Project (State Clearinghouse #20200120330) was completed in compliance with the California Environmental Quality Act (CEQA), was reviewed and considered by the County Planning Commission before project approval, and reflects the County's independent judgment and analysis.
3. CERTIFY the EIR prepared for the project.
4. ADOPT the CEQA findings for the project.
5. ADOPT the Mitigation Monitoring and Reporting Program for the project.
6. ADOPT the statement of overriding considerations for the project.
7. DIRECT the Department of Conservation and Development to file a CEQA Notice of Determination with the County Clerk.
8. SPECIFY that the Department of Conservation and Development, located at 30 Muir Road, Martinez, CA, is the custodian of the documents and other material which constitute the record of proceedings upon which the decision of the Board of Supervisors is based.
9. DENY the appeal of Natural Resources Defense Council, et.al.; Charles Davidson; and the Crockett Community Foundation.
10. APPROVE the Phillips 66 Rodeo Renewed Project.
11. APPROVE the findings in support of project.
12 APPROVE the conditions of approval for the project.
13. APPROVE the attached Community Benefits Agreement.

05-03-2022 D.1 and D.2

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

Letters received for Board consideration
Packet I

Pg 1	Valerie Carpenter, El Cerrito	4/29/2022	form-EIR	oppose
Pg 2	Christopher Martin, Richmond	4/29/2022	form-EIR	oppose
Pg 3	Linda Ostro, Rossmoor	4/29/2022	form-EIR	oppose
Pg 4	Michael D'Adamo, Ph.D, Kensington	4/29/2022	form-EIR	oppose
Pg 5	Bridget Wellerstein, MS. Ed., OTL, Lafayette	4/29/2022	form-EIR	oppose
Pg 6	Daniel Rodriguez	4/29/2022	form-EIR	oppose
Pg 7	Mady Martin, Richmond	4/29/2022	form-EIR	oppose
Pg 8	Lynne Oliver, Richmond	4/29/2022	form-EIR	oppose
Pg 9	Theresa Dixon, Urban Tilth, Richmond	4/29/2022	form-EIR	oppose
Pg 10	Marti Roach	4/29/2022		oppose
Pg 11	Margaret C. Murray, Pinole	4/29/2022	form-EIR	oppose
Pg 12	Sophie Van Ronsele, Richmond	4/29/2022	form-EIR	oppose
Pg 13	Peter Freedman, El Cerrito	4/29/2022		oppose
Pg 14	Emily H. Hopkins, Walnut Creek	4/29/2022	form-EIR	oppose
Pg 15	Susanna Marshland, Kensington	4/29/2022	form-EIR	oppose
Pg 16	Jean Evans, Concord	4/29/2022	form-EIR	oppose
Pg 17	Lisa Jackson	4/29/2022	form-EIR	oppose
Pg 18	Arthur Clinton, El Cerrito	4/29/2022	form-EIR	oppose
Pg 19	Michael Domagalski, Port Costa	4/29/2022	form-EIR	oppose
Pg 20	Marci Armstrong, Rodeo	4/29/2022	form-EIR	oppose

From: Firemonkey14 <: net>
Sent: Friday, April 29, 2022 8:17 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
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- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Valerie Carpenter

El Cerrito, CA

From: christopher martin < .com>
Sent: Friday, April 29, 2022 8:29 AM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs.

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Vote to reject. Thank you.

Christopher Martin

Richmond, CA. 94805

From: Linda Ostro <l
Sent: Friday, April 29, 2022 8:40 AM
To: Clerk of the Board
Subject: RE: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

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Thank you!

A concerned citizen,

Linda Ostro, Rossmoor resident, Walnut Creek

From: Michael D'Adamo < n>
Sent: Friday, April 29, 2022 8:42 AM
To: Clerk of the Board
Subject: Decision on Biofuels

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

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In addition, the fossil fuel industry is seeking ways to survive. While that is completely understandable, it is time to recognize that putting any GHGs in the atmosphere has to end to prevent catastrophic conditions that threaten the existence of our species.

Sincerely,

Michael D'Adamo, Ph.D.

Kensington resident

From: Bridget Wellerstein <
Sent: Friday, April 29, 2022 8:55 AM
To: Clerk of the Board
Subject: Biofuels EIR

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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Sincerely,

Bridget Wellerstein M.S. Ed., OTL

(Lafayette)

Stacey Boyd

From:	Daniel Rodriguez < ail.com>
Sent:	Friday, April 29, 2022 9:25 AM
To:	Clerk of the Board
Subject:	Reject Biofuels Projects

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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From: Mady Martin < jmail.com>
Sent: Friday, April 29, 2022 9:45 AM
To: Clerk of the Board
Subject: Protect Our Environment, reject land use permits

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Vote to reject. Thank you.

Mady M.

Resident of Richmond, CA. 94805

From: Lynne Olivier <lynneo2@comcast.net>
Sent: Friday, April 29, 2022 9:46 AM
To: Clerk of the Board
Subject: Land Use Permits

Dear Contra Costa Supervisors,

Please reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,
Lynne Olivier
Richmond, CA 94805

From: theresa dixon >
Sent: Friday, April 29, 2022 10:33 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

--
THERESA DIXON
Urban Tilth
CSA Procurement Manager
323 Brookside Dr
Richmond, California 94801
303-596-1048

June McHuen

From: Marti Roach
Sent: Friday, April 29, 2022 10:43 AM
To: Clerk of the Board
Cc: martiroach@gmail.com
Subject: May 3rd BOS Meeting: Marathon and P66 EIRS

Importance: High

Follow Up Flag: Follow up
Flag Status: Completed

Dear Contra Costa Supervisors,

It is important to the community that you slow down the EIR process on the Phillips 66 and Marathon Refinery biofuels projects. Highly technical and well documented comments from multiple public interest, environmental justice and environmental groups have detailed failures in the EIR.

Remember the precautionary principle: in new projects where uncertainty over immediate and long-term impacts exist, responsible decision makers should exercise caution, and pause and review before leaping into new innovations that may prove disastrous.

Some of the failures of the EIR include:

- Not taking into account climate impacts (remember you have acknowledged we are in a climate emergency),
- Not taking into account the impacts of burning food for fuel as demand for feedstock production skyrockets,
- Risks and environmental degradation due to feedstock production,
- Risks related to safety and air air quality due to the scale of these projects and potentially increased operational accidents like flaring, explosions and gas releases.

A more rigorous assessment is needed.

Thank you all for your service to our County,

-Marti Roach

June McHuen

From:	Margaret Murray :mail.com>
Sent:	Friday, April 29, 2022 10:52 AM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs
Follow Up Flag:	Follow up
Flag Status:	Completed

Dear Contra Costa Supervisors,

I am writing to you (for my very first time after living in Concord and now in Pinole for 40 years) to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
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The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Margaret C. Murray
Pinole, CA

June McHuen

From: Sophie Van Ronselé
Sent: Friday, April 29, 2022 11:18 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Follow Up Flag: Follow up
Flag Status: Completed

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

In community,

Sophie Van Ronsele
Richmond, CA

Sophie Van Ronselé
(All Pronouns)
+1 415-216-3376

"The future of our earth may depend upon the ability of all women to identify and develop new definitions of power and new patterns of relating across difference."
- Audre Lorde

June McHuen

From: Peter Freedman
Sent: Friday, April 29, 2022 11:25 AM
To: Clerk of the Board
Subject: Biofuels

Vote "No." on BioFuels. in Contra Costa County.
Peter Freedman

El Cerrito, CA
94530

June McHuen

From: Emily Hopkins < m>
Sent: Friday, April 29, 2022 11:25 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Follow Up Flag: Follow up
Flag Status: Completed

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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And I believe analysis using current science on biofuels, including the social and human costs of shifting from food production to fuel production, will show that this shift is not in the immediate or long term interest of our local or global community.

Sincerely,

--
Emily H. Hopkins
Walnut Creek, CA 94598
http://www.linkedin.com/in/emily1hopkins

June McHuen

From:	Susanna M < l.com>
Sent:	Friday, April 29, 2022 11:30 AM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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--
Susanna Marshland, Kensington 94707

June McHuen

From:	Jean Evan: .com>
Sent:	Friday, April 29, 2022 11:50 AM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I am a Concord resident and I am very concerned about the environmental impact of the proposed biofuels projects. I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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Thank you,

Jean Evans, Concord, CA 94518

From: Lisa Jackson · >
Sent: Friday, April 29, 2022 11:57 AM
To: Clerk of the Board
Subject: Please Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

As a resident of unincorporated Contra Costa County, I am requesting that you reject the land use permits for Phillips 66 and Marathon Refinery biofuels projects and require an additional environmental impact review. There are serious concerns from many environmental groups on aspects of the project not addressed by the draft EIRs. There are long term consequences for the people of your county and even wider impacts for the planet, if these projects are adopted without fully addressing those concerns around safety and land use.

The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
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Thank you,

Lisa Jackson.

June McHuen

From:	Arthur Clinto[redacted]n>
Sent:	Friday, April 29, 2022 12:54 PM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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Thank you.

Arthur Clinton, Jr.

El Cerrito

From: Michael Domagalski
Sent: Friday, April 29, 2022 1:18 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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Michael Domagalski
Port Costa, CA 94569

mailed to BOS 04-29-22

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

Letters received for Board consideration

Packet 2

Pg 1	J.A. Zaitlin, Kensington	4/29/2022	form-EIR	oppose
Pg 2	Cori Pansarasa, El Cerrito	4/29/2022	form-EIR	oppose
Pg 3	Marcia Liberson, Walnut Creek	4/29/2022	form-EIR	oppose
Pg 4	Cathy Druck, Crockett	4/29/2022	form-EIR	oppose
Pg 5	Betty Lobos, Concord	4/29/2022		oppose
Pg 6	Bonnie Pannell, Crockett	4/29/2022	____	oppose
Pg 7	Jane Courant, Richmond	4/30/2022	form-EIR	oppose
Pg 8	Jackie Mann, 350 Contra Costa	4/30/2022		oppose
Pg 9	Ogie Strogatz, Walnut Creek	4/30/2022		oppose
Pg 10	Janet Pygeorge	4/30/2022		
Pg 11	Denice A. Dennis, 1000 Grandmothers for Future Generations	4/30/2022		oppose
Pg 12	Cynthia Mahoney, M.D., Climate Health Now; Medical Society Consortioum on Climate & Health; Clinical Associate Professor of Medicine, Stanford Universtiy (ret)	4/30/2022		oppose
Pg 13	Nora Privitera, Oakland	4/30/2022		oppose
Pg 14	Jennifer Russell, Walnut Creek	4/30/2022		oppose
Pg 15	Nick Ratto, City of Alameda; 350 Bay Area Action	4/30/2022	form-EIR	oppose
Pg 16	Diane Dulmage, Richmone	5/1/2022	form-EIR	oppose
Pg 17	Michael Freeman, El Cerrito	5/1/2022		oppose
Pg 18	Mike Moore, Oakley (Marathon)	5/1/2022	form-EIR	oppose
Pg 19	Mike Moore, Oakley (Phillips 66)	5/1/2022	form-EIR	oppose
Pg 20	Emily Wheeler, Walnut Creek	5/1/2022	form-EIR	oppose
Pg 21	Debi Clifford	5/1/2022		oppose
Pg 22	Jeffrey Mann, Lafayette	5/1/2022		oppose
Pg 23	Vanessa Warheit, El Cerrito, EV Charging Access for All; Emerge CA Class of '21	5/1/2022		oppose
Pg 24	Marinell Daniel, El Sobrante	5/2/2022		oppose
Pg 25	Elena Engel, San Francisco	5/2/2022		oppose
Pg 26	Helena Birecki, 350 Bay Area	05-2-022		oppose
Pg 27	Scott Bartlebaugh, Crockett Improvement Association	5/2/2022		oppose
Pg 28	Roland Saher, Live Oak	5/2/2022		oppose

From: Marcia L. om>
Sent: Friday, April 29, 2022 4:53 PM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,
I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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Sincerely,

Marcia Liberson, Walnut Creek CA

From: cathy druck :om>
Sent: Friday, April 29, 2022 5:07 PM
To: Clerk of the Board
Subject: Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

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- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

These projects *must* have a more thorough EIR.

I appreciate your attention to this matter

Catherine Druck

Crockett, California

From: Betty Lobos < .net>
Sent: Friday, April 29, 2022 6:03 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa County Supervisors,

I am concerned about the environmental impact reviews (EIRs) for the Phillips 66 and Marathon Refinery biofuels projects. Comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of those points. I urge you to reject the land use permits and to require additional EIRs.

The final EIRs inadequately meet the following expectations:

Providing an adequate, detailed project description
Accounting for safety and air pollution concerns from potential hazards such as flaring, explosions, gas releases, and increased use of hydrogen
Accounting for impacts of burning human food as "feedstock" in biofuel production
Adequately considering climate impacts
Complying with the CEQA Requirement to respond to public comments

I was proud when my county declared a Climate Emergency that commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects must have a more thorough EIR.

Sincerely,
Elizabeth (Betty) Lobos
Concord, CA

From:	Bonnie Pannell <
Sent:	Friday, April 29, 2022 9:41 PM
To:	Clerk of the Board
Subject:	Please Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I live in a "cancer belt" because of the refineries near me, such as Phillips 66. Communities such as mine are pacified with occasional public meetings sponsored by the county government with representatives giving lip service to a plan of environmental improvements, but it never happens. What we get is the status quo or something worse. Our country is on a trajectory toward severe global warming and extinction and, yet, we still give more consideration to the big polluters than we do the health of the planet. As the advice goes, "think globally, act locally." I hope you will align with that slogan in all of your deliberations.

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Bonnie Pannell
St.
Crockett, Ca 94525

From: Jane Courant < .com>
Sent: Saturday, April 30, 2022 6:42 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Hi Dear Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

SIncerely yours,

Jane Courant

iz Avenue

Richmond 94804

From:	jackie mann <[illegible]@att.net>
Sent:	Saturday, April 30, 2022 8:18 AM
To:	Clerk of the Board
Subject:	May 3rd Appeal for on Renewable Fuels Projects for Marathon and Phillips 66

Please submit my letter to the Supervisors and for the record.
Sincerely,
Jackie Garcia Mann, 350 Contra Costa
Lafayette

Dear Supervisors, 29 April 2022

The purpose of CEQA is to create actions to mitigate environmental impacts. Likewise, these EIRs are vague, generalized and ignore many impacts which require mitigation. This is a violation of CEQA and creates legal jeopardy for the county. As the Appeals from environmental groups focus on specific failures of the EIR, **I wish to address the lack of guardrails and limits. These projects purposely have vague and open-ended descriptions, which may not reflect what is actually implemented.**

The refineries should post bonds for clean up and remediation of these hazardous refinery sites and risk bonds for accidents. **This should begin immediately, while there is leverage for this permit** (not 15 years down the road as currently proposed). If the companies fail, taxpayers will be burdened with expensive toxic cleanup sites that negatively impact community health, local economics, and property values. It is not fair to externalize these economic risks onto the communities. The externalized health impacts are bad enough.

For instance, if state policy changes and LCFCs are removed or biofuel refining is no longer economically feasible, these refineries may close with short notice. This is apparent in the recent closing of Marathon Refinery for economic reasons. They could sit "idle" for decades with little hope to reopen and no plan or financing for clean up. **Bond the cleanup/decommissioning in advance as a condition of approval**.

The land-use permits should specify exact products and maximum production amounts. There is no limit on throughputs. As currently written, the refineries can double the proposed production or switch to SAF or some other bio-product. This would have health and safety impacts NOT EVALUATED in the current EIRs. Guardrails should include production caps which apply to specific products and require a new permit for new biofuel products, SAF, or different ratios of products.

When refineries seek to produce Sustainable Aviation Fuel (SAF) as a main product, require a new land use permit and EIR review.

What are the limits on petroleum refining? As written, the Phillips 66 permit allows "temporary increase" in petroleum refining. How can EIR impacts be evaluated without specific information compared to current operations? This is an open ticket. Do current permits for petroleum refining expire? **Specify an end-date and amount.**

Community Recourse: **Pollution, noise, odors, explosions, flaring, fires, oh my!**
These things happen now and may increase with increased hydrogen cracking needed for biofuel refining. Regulatory agencies and fines have done little. Sink some teeth into this land use permit and safeguard the frontline community with **conditions of approval that retain local authority** to shutdown the refineries for violations or being a bad neighbor. **BOS, protect your people!**

From: Ogie Strogatz <[redacted]mail.com>
Sent: Saturday, April 30, 2022 8:20 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Respectfully,

Ogie Strogatz

[redacted], Walnut Creek CA 94597

Sent from my iPhone

From:	Denice A Dennis < ...mph@gmail.com>
Sent:	Saturday, April 30, 2022 12:00 PM
To:	Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc:	Clerk of the Board
Subject:	Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's [Declaration of Climate Emergency] commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Denice A. Dennis, MPH

1000 Grandmothers for Future Generations

From: cynthia mahoney <[illegible]@comcast.net>
Sent: Saturday, April 30, 2022 1:20 PM
To: Clerk of the Board
Cc: Jackie Mann
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
    - *The surrounding community already suffers from high pollution and excessive asthma and cancer which must be addressed and mitigated.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
    - *This is especially important as we see heat and other climate disasters impacting food supplies, like the situation now in India with devastating effects on the wheat crop*
- *Failure to consider climate impacts*
    - *We have to stop burning things - not just fossil fuels, but burning and releasing carbon. We have to stop clearing land to grow things to burn - which doubly impacts the carbon cycle imbalance.*
- *Failure to account for cumulative impacts*
    - The experience with corn ethanol shows how easily a "feel good' proposal can be a boondoggle which does not actually lower total emissions.
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents.

For all these reasons, these projects *must* have a more thorough EIR.

Cynthia Mahoney MD

Climate Health Now
Advocate for the Medical Society Consortium on Climate & Health
Clinical Associate Professor of Medicine, Stanford University(ret.)

From:	Nora Privitera ....cast.net>
Sent:	Saturday, April 30, 2022 4:14 PM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Nora Privitera
Oakland, CA

From: Jennifer Russell <
Sent: Saturday, April 30, 2022 4:16 PM
To: Clerk of the Board
Subject: Letter to Supervisors

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Yours Truly,

Jennifer Russell

Walnut Creek CA 94595

From: ratto
Sent: Saturday, April 30, 2022 6:58 PM
To: Clerk of the Board
Subject: Contra Costa Supervisors - Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews (EIRs) for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,
Nick
Nick Ratto
Legislative Lead - Transportation
City of Alameda
350BayArea ACTION

From: Diane D <
Sent: Sunday, May 1, 2022 11:19 AM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIR

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR

Diane Dulmage

Richmond 94804

Dilicious50@gmail.com

From: M 064 Freeman <
Sent: Sunday, May 1, 2022 12:46 PM
To: Clerk of the Board
Subject: [BULK] Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

Biofuels are not clean energy!

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- *Failure to Comply with the CEQA Requirement to Respond to Public Comments*

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you,

Michael Freeman
El Cerrito, CA

From: Mike Moore < hoo.com>
Sent: Sunday, May 1, 2022 1:11 PM
To: Clerk of the Board
Subject: May 3 Meeting – Item D.2 – Phillips 66 Appeal

Dear Supervisors,

I urge you to reject the land use permit granted by the Planning Commission and require additional EIR reviews for Phillips 66 Refinery biofuels projects and grant the further CEQA reviews requested by the 3 appellants. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use.

The FEIRs inadequately address the following concerns:

- Failure to provide an adequate project description.
- Failure to provide a correct baseline due to lack of petroleum feedstock
- Concern with Unit 250 in the Project Analysis
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.
- Failure to account for impacts of burning food for fuel due to human food used as a "feedstock" in biofuel production
- Failure to consider climate impacts.
- Findings Concerning Choice of Alternatives and Throughput Volumes
- Failure to account for cumulative impacts.
- Failure to provide adequate resources for remediation of the site once it ceased biofuel production
- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency Resolution 2020/256 commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough review of the EIR.

Thank You,

From: Mike Moore ıoo.com>
Sent: Sunday, May 1, 2022 1:22 PM
To: Clerk of the Board
Subject: May 3 Meeting – Item D.1 – Marathon Appeal

Dear Supervisors,

I urge you to reject the land use permit granted by the Planning Commission and require additional EIR reviews for Marathon Refinery biofuels projects and grant the further CEQA reviews requested by the appellants. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the specific points, especially those relating to safety and land use.

The FEIRs inadequately address the following concerns:

- Failure to provide an adequate project description.
- Failure to provide a correct baseline due to shutdown of the refinery operations
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.
- Failure to account for impacts of burning food for fuel due to human food used as a "feedstock" in biofuel production
- Failure to consider climate impacts.
- Findings Concerning Choice of Alternatives and Throughput Volumes
- Failure to account for cumulative impacts.
- Failure to provide adequate resources for remediation of the site once it ceased biofuel production
- Failure to Comply with the CEQA Requirement to Respond to Public Comments

The Contra Costa County's Declaration of Climate Emergency Resolution 2020/256 commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough review of the EIR.

Thank You,

Mike Moore

From: Emily Wheeler <[redacted]m>
Sent: Sunday, May 1, 2022 2:22 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional Environmental Impact Reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Sincerely,

Emily Wheeler

Walnut Creek

Stacey Boyd

From:	Debi Clifford
Sent:	Sunday, May 1, 2022 6:20 PM
To:	Clerk of the Board
Subject:	Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

As a longtime Contra Costa taxpayer and landlord, I urge you to reject the land use permits for the Phillips 66 and Marathon Refinery biofuels projects and conduct more thorough environmental impact reviews.

In this crucial moment, the County has the leverage of the permitting process to insist that these two companies do the hard work now of proving that these projects will not irremediably and significantly harm local residents, our communities, our food supply, and the environment.

To date, the companies have failed to comply with the ***CEQA requirement to respond to public comments,*** as they have not responded in detail to the concerns submitted in writing by local environmental groups. Specifically, they have failed to address:

- ***Safety and air pollution concerns*** *from potentially increased operational hazards including flaring, explosions, gas releases, and increased use of hydrogen*
- ***Impacts of burning food*** *for fuel due to human food used as "feedstock" in biofuel production*
- ***Climate and other environmental impacts***

Please do your due diligence now: don't rubber-stamp this project in your haste to nail down a solution to our county's overdependence on local fossil fuel production. You have the responsibility and authority to take more time to thoroughly analyze these biofuels conversions which offer a seductive energy alternative that – like the Trojan horse – more likely will unleash untold harm on local residents and exacerbate the climate crisis we all face.

Thank you for your service and for your serious attention to this matter.

Sincerely,

Debi Clifford
Richmond, CA

From: Jeffrey Mann < t>
Sent: Sunday, May 1, 2022 9:55 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I have lived in CCC for 25 years, and have raised my family here.
I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's Declaration of Climate Emergency commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects *must* have a more thorough EIR.

Thank you for your consideration.

Jeffrey Mann, MD
Lafayette

From:	Vanessa Warhei:
Sent:	Sunday, May 1, 2022 11:26 PM
To:	Clerk of the Board
Cc:	John Gioia
Subject:	Reject the EIRs for proposed Renewable Fuels Project

Dear Contra Costa Supervisor,

I am very concerned about the proposed biofuel projects currently under consideration. I understand that these projects purport to improve the health and climate impacts of the existing refineries, but the facts do not seem to support either of these assumptions -- if anything they point to increasing both GHG impacts and health impacts to our local communities.

I therefore urge you to reject the land use permit and require additional EIR reviews for both Phillips 66 and Marathon Refinery biofuels projects. I am very concerned that joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project, yet the responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. Specifically, the FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. I applaud you for taking this step -- now it's time to take the next step, and demand the refineries come back with a more thorough EIR so you can make an educated decision about the merits of these proposals.

Thank you for protecting our communities. I look forward to hearing back from you on this issue.

Warm regards,
Vanessa Warheit
El Cerrito, CA

--

Vanessa Warheit

Phon

EV Charging Access for All

Emerge CA Class of '21

pronouns: she, her, hers
https://linktr.ee/vwarheit

From:	Marinell Daniel < ail.com>
Sent:	Monday, May 2, 2022 7:43 AM
To:	Karen Mitchoff; John_Gioia; Supervisor Candace Andersen; Diane Burgis
Cc:	Clerk of the Board
Subject:	Items D1and D2, BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Regards,

Marinell Daniel,

..., El Sobrante, CA 94803

Sent from my iPad

From: Elena Engel < il.com>
Sent: Monday, May 2, 2022 7:52 AM
To: Clerk of the Board
Subject: Biofuels EIRs

The EIR does not take into account all of the impacts from refining biofuels. One of the most egregious omissions is that biofuels have been shown to create more greenhouse gases than they avoid. The use of food crops for fuel is an unfortunate choice with many unintended consequences, including driving up the cost of commodities, and using more ghg-creating inputs when growing such crops.
Biofuels are not the answer. They continue to pollute the air around the refineries and they continue to create unacceptable amounts of greenhouse gases.
I urge you to reject this application, and require an actual EIR that takes into account all the impacts, rather than cherry picks what will appear more advantageous,
Elena Engel
San Francisco

From: Helena Birecki · |>
Sent: Monday, May 2, 2022 11:01 AM
To: Clerk of the Board
Subject: Uphold the Appeals of Renewable Fuels Projects EIRs-- press pause on these projects

Dear Supervisors,

Please uphold the appeals from numerous community and environmental groups-- put a pause on the projects until the companies do a more thorough EIR that addresses the inadequacies brought up in the appeal.

It is essential that you reject the EIR as it stands not only for public health and safety, but also legal precedent that will negatively impact Contra Costa County first, and then communities across the country.

Especially concerning for public health and safety is the:

- Near-term increased risk of flaring and risk of explosion due to increased use of hydrogen for biofuels processing
- Medium term increased risk of food shortages due to so much agricultural land being shifted from food production to fuel feedstock, and
- Long-term risk of these refineries shutting down with no decommissioning plans

Especially concerning for legal precedent would be:

- Approving an Environmental Impact Report that fails to comply with legal requirements including providing an adequate project description and adequately responding to public comments.

Please uphold the law by upholding the appeals. Put a pause on the two renewable fuels projects until a more legally sound EIR that adequately addresses public health and safety is completed.

Thank you,
Helena Birecki
member of 350 Bay Area

From: Scott Bartlebaugh < l.net>
Sent: Monday, May 2, 2022 11:03 AM
To: Clerk of the Board
Subject: Public Comment on agenda item D2 Hearing regarding Rodeo Renewed project, Board of Supervisors meeting Tuesday May 3, 2022

Clerk, Board of Supervisors,

I submit the following public comment on behalf of the Crockett Improvement Association.

May 2, 2022

Re: Comment on Phillips 66 Rodeo Renewed Project -- Community Benefit Agreement

Contra Costa County Board of Supervisors,

I'm making a comment representing the Crockett Improvement Association regarding the Phillips 66 Rodeo Renewed Project Public Hearing. We believe the project has positive aspects such as a reduction in total emissions, a reduction in hazardous materials and process safety risk to the surrounding public, as well as supports an overall move to lower impact energy sources.

We have concerns with the current lack of definition of the Good Neighbor Agreement. Crockett, Port Costa, and Tormey are fenceline communities that are affected by the planned operation, permitted emissions, and any unplanned incidents that may occur in the course of operation. We request that the Crockett, Port Costa, and Tormey communities be included in discussions of the details of the Community Benefit Agreement. While this may be the plan it was not clear from the discussion at the Planning Commission hearing. This is a matter of environmental justice. A variety of incidents are documented on the Contra Costa County Health Services website, https://cchealth.org/hazmat/accident-history.php, including the Catacarb release in 1994 and incidents as recent as 2015. Crockett was included in a Good Neighbor Agreement following the 1994 Catacarb incident resulting in payments to the Crockett Community Foundation, and we believe a similar agreement with benefit through the Crockett Community Foundation would be appropriate.

Furthermore we believe the Crockett Community Foundation is the most appropriate body and means to administer the management and distribution of funds to the Crockett, Port Costa, and Tormey community. The Crockett Community Foundation has a significant track record of administering other Community Benefit Agreement, mitigation, and similar funds to the community. They are an elected board and have a track record of financially responsible and community engaging management of such funding.

Lastly we ask that odor control from the new project be managed with a well defined performance and enforcement structure. While the new project reduces hazardous materials inventories and

From: Roland Saher < >
Sent: Monday, May 2, 2022 1:45 PM
To: Clerk of the Board
Subject: Reject Renewable Fuels Project's EIRs

Dear Contra Costa Supervisor,
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points,** especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
  - **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough EIR.

Even though I am not a resident of Contra Costa County - I live in Live Oak, near Capitola - I believe that this is a precedent setting plan that might well affect all parts of California in a negative way and calls, therefore, for a stringent EIR.
Thank you.
Roland Saher

Land use permit for the Martinez Refinery Renewable Fuels Project at 150 Solano Way in Pacheco

Land use permit for the Phillips 66 Rodeo Renewable Project at 1380 San Pablo Ave in Rodeo

	Letters received for Board consideration **Packet 3**			
Pg 1	Valerie Ventre-Hutton	5/3/2022		oppose
Pg 2	Rebecca Auerbach	5/3/2022		oppose
Pg 26	Maureen Brennan	5/3/2022		oppose
Pg 27	Nanlouise Wolfe	5/3/2022		oppose
Pg 28	Kathy Kerridge	5/3/2022		oppose
Pg 29	Gail Susan Gordon, LMFT, SEP	5/3/2022		oppose
Pg 31	Kathleen Rodgers	5/3/2022		oppose
Pg 32	Woody Hastings, The Climate Center	5/3/2022		oppose
Pg 35	Lisa Argento Martell	5/3/2022		oppose
Pg 36	Lis Sibony	5/3/2022		oppose

Stacey Boyd

From: Valerie Ventre-Hutton [redacted]
Sent: Monday, May 2, 2022 4:43 PM
To: Clerk of the Board
Subject: May 3rd BOS meeting: Marathon and P66 biofuels projects/FEIRs

Dear Contra Costa Supervisors,

As a long-term resident of Contra Costa County, I ask that you slow down the EIR process on the Phillips 77 and Marathon Refinery biofuels projects and demand EIRs that are significantly more comprehensive, specific, and address community concerns.

Multiple community and environmental groups submitted joint comments on the draft EIRs that included detailed, specific points about numerous technical aspects of the project. In contrast, the final EIRs provide generalized, vague responses and are dismissive of many impacts that require mitigation including:

- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts, especially in light of CCC's Declaration of Climate Emergency;*
- ***Failure to account for cumulative impacts***
- *Failure to Comply with the CEQA Requirement to Respond to Public Comments*

If one purpose of CEQA is to create actions to mitigate environmental impacts, then the documents submitted are inadequate, potentially in violation of CEQA, and more importantly do not provide the foundational guidance needed to safeguard communities and our county. These projects *must* have a more thorough EIR.

Thank you for your work on behalf of our Contra Costa communities.

Valerie Ventre-Hutton

[redacted] Walnut Creek, CA

Stacey Boyd

From: Rebecca Auerbach [redacted]
Sent: Monday, May 2, 2022 4:48 PM
To: Clerk of the Board
Subject: Please reject the EIRs for biofuels projects

Dear Supervisors,

I am deeply concerned about the proposed biofuel projects at local refineries. Biofuels are a false solution. They offer only a new way to emit greenhouse gasses and threaten the health and safety of frontline communities, in stark contrast to the real climate solutions in sustainable electrification.

I urge you to reject these land use permits, require more thorough Environmental Impact Reports, and regard these projects with extreme wariness about their effects on our community and the climate.

Regards,

Rebecca Auerbach
Pleasant Hill, CA

RODEO CITIZENS ASSOCIATION

5/2/22

To: Contra Costa Board of Supervisors, and,
County Planning Commission of Contra Costa County Dept. Of Conservation & Development

As a group of concerned citizens of the town of Rodeo, we are respectfully requesting an appeal of the Planning Commission's decision to recommend approval of the Phillips 66 Rodeo Renewed land use permit.

Our grounds for appeal are these:

- The details of the Community Benefits Agreement and the conditions of the project are insufficiently defined as to the magnitude and nature of any actual benefit. The decision on this land use permit should be tabled until the details of this agreement are in place. (1)

- Rodeo is classified as a disadvantaged community by Contra Costa County. SB 1000 requires Contra Costa County to integrate environmental justice into the General Plan. This law is based on the understanding that certain communities have experienced a combination of historic discrimination, negligence, and political and economic disempowerment. We here in Rodeo have long experienced a disproportionate burden of pollution and health impacts, noise and odors. (2)

- Phillips 66 has claimed an "extensive odor remediation program" with no details. Details of the plan should be a condition for approval before the permit is granted.

- The hydrogen plant has been ignored in the draft EIR, nor addressed by the Planning Commission. The Air Liquide plant is not capable of the planned increase of methane-fuel consumption, which risks explosion, and at the least, increased flaring events. Investigation of the capability of this plant facility should also be a condition for approval before the permit is granted. Air Liquide has a history of yearly "unit upset" since it went on line in 2009.

Thank you for considering our concerns.

Rodeo Citizens Association, members;

Janet Pygeorge, President; Rodeo
Janet Callaghan; Rodeo
Mike Coody; Rodeo
Elaine Wander; Rodeo
Bod Houseman; Rodeo
Charles Davidson; Hersules
Please respond to RCA:
2108 Drake Lane Hercules CA 94547
(510) 837-8441

CDavidson

And Maureen Brennan; Rodeo

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1) The Rodeo Renewed Project is planned on being an 80,000 barrel per day project for refining 1.22 billion gallons per year. At up to $3.32 per gallon for California Low Quality Fuel Standards credits and Federal Renewable and Blenders Tax credits, up to $3 billions yearly in subsidies (and in-kind subsidies) could be provided to the refinery to produce renewable diesel. If only one cent per gallon from those subsidies were to be provided to the Town of Rodeo as a community benefits package within a Good Neighbor Agreement, $12 million yearly could go to community improvements, such as recreation, education, nature and aesthetics.

- Overcapacity Looms as More and More US Refiners Enter Renewable Diesel Market. Stratas Advisors. (June 11, 2020) https://stratasadvisors.com/Insights/2020/06112020LCFS-RD-Investment

2) Demographics: The town of Rodeo, where the Phillips 66 refinery is located, is a minority-majority and working-class community impacted by heavy exposure to pollution and other hazards. Sixty-six percent of Rodeo's population of 8,679 consists of people of color: 34% is Hispanic, 17% is Asian American, and 15% is African American, according to 2018 U.S. Census estimates. Forty-four percent of its population is white.(1) Rodeo is a low-income community, with a per capita income of $34,356, according to U.S. Census 2018 estimates. The Census places the poverty percentage at 14%, although CalEnviroScreen 3.0 doubles that figure, indicating that 31% of Rodeo's residents live below twice the federal poverty level.(2) A largely African-American community lives in county-owned Section 8 housing located directly at the Phillips 66 refinery fenceline. Little population growth and new home building is expected in Rodeo and there is no supermarket.

It is designated by the State of California, as a Disadvantaged Community by the Office of Environmental Health Hazard Assessment (OEHHA), and assigned a CalEnviroScreen 3.0 percentile of 80-85% (per Sept 2021). This ranking indicates that its residents endure a greater combination of pollution and other environmental stressors than 80-85% of the state. Healthwise, Rodeo falls within the 98th percentile for asthma and 92nd percentile for low birth weight, and within the 75th percentile for cardiovascular impacts. Its exposure to hazardous waste places it in the 98th percentile, to impaired water within the 86th percentile, and to toxic releases within the 78th percentile. (2) As part of the Rodeo-Hercules Fire Protection District, Rodeo has three times the per capita emergency medical response rate as the adjacent middle-class community of Hercules. In addition to its burden of disproportionate environmental harms and public health deficits, Rodeo is also an unincorporated community with a paucity of available services. The absence of a municipal government and the ongoing inadequacy of material resources are two major factors that contribute to the historic lack of being qualified for additional outside resources.

1. https://www.census.gov/quickfacts/fact/table/rodeocdpcalifornia,US/PST045218
2. See https://oehha.ca.gov/calenviroscreen/maps-data.

Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.
charlesdavidson@me.com Hercules CA. 11 April 2022

11 April 2022 [Updated 4/21/2022]

Re: Appeal of Contra Costa County Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project (File No. LP20-2040 and the Contra Costa County Code, section 26-2.2406)

To the Contra Costa County Board of Supervisors:

The appellant requests that the Board of Supervisors grant this appeal, to reject certification of the Phillips 66 San Francisco Refinery Rodeo Renewed Project FEIR, and instruct the Contra Costa County Department of Conservation and Development and the Planning Commission to develop a revised DEIR, that meets the requirements of CEQA, to be prepared and circulated for public comment.

The Phillips 66 Refinery's Rodeo Renewed Project Draft Environmental Impact Report (DEIR) and Final EIR did not acknowledge that making refinery biodiesel, or so-called renewable diesel, from hydrogenated vegetable oils and animal fats is as energy-consuming, carbon dioxide (CO2) greenhouse gas emitting and "carbon-intensive" to refine as the world's dirtiest, most dense and highest sulfur crude oils.

This appeal, is based exclusively upon the refinery portion of the total carbon intensity of renewable diesel and counterintuitively, is solely focused on the exceptionally high carbon intensity needed to process triglyceride oils into renewable diesel fuel. Notably, on a per barrel basis, the Phillips 66 Refinery's anticipated post-Project per barrel Renewable Diesel CO2 emissions would greatly exceed the per barrel CO2 emissions of the refinery's current average high-sulfur, heavy petroleum feedstock.

The County planning commission decision to certify the Final Environmental Impact Report 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 argument set forth in this appeal letter; the comments submitted concerning the failure of the Draft Environmental Impact Report (DEIR) and Final EIR (FEIR) to provide an adequate pre-project, per barrel carbon intensity baseline, which would demonstrate the post-project, per barrel, carbon intensity increase. The DEIR and FEIR also failed to provide an adequate project description which would justify the Project's renewable diesel product as factually low-carbon.

The project's DEIR and FEIR described a renewable diesel product which is inconstant with California climate pathways and neither document justified the project's renewable diesel product as qualified for California Low Carbon Fuel Standard (LCFS) credit-based subsidization.

Failure to provide an adequate project description.
Improper baseline.
Inconsistency with California climate pathways.

I

The DEIR and the FEIR do not clearly demonstrate that the refinery's product is low in embedded carbon dioxide emissions, as required by the California Air Resources Board's Low Carbon Fuels Standard's certification process. The actual numbers published in Phillips 66's own DEIR for their Project, which stipulated expected energy usage, hydrogen requirements and CO2 greenhouse gas emissions, when analyzed, clearly indicate that their renewable diesel (on per barrel basis) is extraordinarily energy-intensive to process and thus, is not a low-carbon product.

Instead of being a feedstock for low-carbon fuel refining, animal fat and vegetable oil molecules are triglycerides (like which physicians measure), and they, counterintuitively, are far more difficult to crack than petroleum oils. The most energy-intensive hydrocracking process for renewable diesel is the hydro-deoxygenation (hydrodeoxygenation) reaction, for which the refinery must greatly expand it hydrogen usage. Renewable diesel fuel produced from a wide array of vegetable oils and animal fats is referred to technically as Hydro-processed Esters and Fatty Acids (HEFA).

In the political or regulatory sphere, if renewable diesel were understood quantitatively as not being a true low-carbon diesel substitute, then such projects would not be certified to qualify for and be approved for California Low Carbon Fuel Standard (LCFS) credits and Federal subsidies.

In the Phillips 66 FEIR master response misleadingly states: "As proposed, the Project would lower facility-wide GHG emissions by about 24,000 MT per year compared to baseline operations. Refer to Table 4.8-5 in the Draft EIR "Annual Project Operational GHG Emissions". This is slightly over only one-percent (1%) of the total project emissions, which is misleading, in that the embedded per barrel CO2 emissions will vastly increase from before the project when refining petroleum feedstock.

However, the basis for the refinery to obtain LCFS credits is that refinery must produce low carbon intensity fuels (on a per barrel basis), although the refinery's DEIR and FEIR only refers to the total refinery greenhouse gas reduction and not the project's future per barrel CO2 emissions increase. LCFS does not require that the whole refinery reduce their total yearly CO2 greenhouse gas emissions, which is due in large part to the decommissioning of obsolete or otherwise stranded assets. In the case of Phillips 66, the reduction in *total* refinery CO2 greenhouse gas derives from decommissioned stranded assets due to the closure of the company's San Luis Obispo County refinery (which had serious long-term decreases of crude availability, as it had no sea port), their planned closure of their problem-laden Line-200 pipeline (which delivered semi-processed petroleum from SLO County to Rodeo), as well as closure of the Carbon Plant on HWY 4.

Uniquely, the Phillips 66 refinery in Rodeo Contra Costa County, is planning on being the world's largest Renewable Diesel biofuels refinery in the world and is about 12 miles away from the Martinez Marathon refinery, which is planning on being the world's second largest biofuels refinery.

For its part, Marathon claims a reduction in carbon dioxide greenhouse gasses of 60% in their renewable diesel project. However, that 60% CO2 reduction comes entirely from the 60% smaller daily throughput_specified by the project and is entirely NOT from the decreased carbon intensity of the renewable diesel, itself. (1)

Similar for Phillips 66's decreased stated project throughput, where the refinery will experience a minimum 33% decrease in throughput (from a 4-year pre-COVID average capacity utilization) of 105,000 barrels per day to a maximum of 80,000 bpd. However, for both refineries, the per barrel CO2 carbon intensities for renewable diesel will actually *increase* significantly (despite the decrease in throughput), because of the corresponding large increase in hydrogen needed for hydrocracking triglyceride oils. (2a-d)

For example, despite the shimmer of Marathon's 60% decrease in throughput, a simple look at their 42% *increase* in total hydrogen production (made from fossil-fuels), combined with their simultaneous *decreased* throughput, results in a 32% per barrel *increase* in carbon intensity. (1)

Again, similar to Marathon, post-Project refinery-wide, Phillips will be producing 35% more hydrogen than with petroleum refining and delivering a renewable diesel product with a 36%-to-55% increase in per barrel Carbon Intensity at the refinery level. (2) [Table 1]

The projected Phillips 66 and Marathon Renewable Diesel products, when compared to the processing energy requirements for heavy petroleum refining, would be twice as carbon intensive as the average U.S. refinery's processing of petroleum and as high or higher than the most carbon intensive refineries. (3-7) [Table 2]

II

"The Petroleum Refinery Life Cycle Inventory Model (PRELIM) is a mass and energy-based process unit-level tool for the estimation of energy use and greenhouse gas (GHG) emissions associated with processing a variety of crude oils within a range of configurations in a refinery." (6)

The following analysis closely correlates the carbon intensity of the Phillips 66 and Marathon projected Renewable Diesel products with a characteristic petroleum diesel hydrocracker assessed in the PRELIM database, which was fed with a high-sulfur, heavy petroleum gas oil (API 14.96; Sulfur 3.35%). The hydrogen usage for the PRELIM heavy, high-sulfur fed hydrocracker is (listed in the footnoted references and Table1), is 36% below the much higher values for the average renewable diesel profiled in this paper. (6) [Table 1]

One can see that the pre-project refinery-level carbon intensity values, as kilograms of CO2 per barrel, for Marathon (49.52 kg CO2/bbl) and especially Phillips 66 (56.68 kg CO2/bbl) are close to the PRELIM hydrocracker carbon intensity score (58.97 kg CO2 /bbl). (1,2 6) Table 2.

These values are well above the average U.S. refinery carbon intensity (40.7 kg CO2e/bbl), as would be expected from the type of petroleum crude that these refineries currently process. (7)

Staring from these baseline values and based upon the refineries' hydrocrackers projected post-project hydrogen requirements, one can see that post-project carbon intensities for renewable diesel rank at the top end of global crude carbon intensity scores (according to the PRELIM database). The global-weighted refinery-level carbon intensity range for crude oil processing is 10.1 – 72.1 kg CO2e/bbl. This is true for the projected post-project carbon intensity scores for renewable diesel production for Marathon (65.35 CO2 kg/bbl) and Phillips 66's Rodeo Renewed Project for both the low estimate 73.53 CO2 kg/bbl and especially, the high estimate 87.79 CO2 kg/bbl (for 80,000 or 67,000 barrels per day scenarios, respectively). See Table 2. (8)

III

The California Air Resources Board (CARB) designates and regulates the CO2 greenhouse gas or carbon intensity (CI) for California transportation fuels, whether they are petroleum based or biodiesel, which includes renewable diesel. According to CARB, "The CI includes the "direct" effects of producing and using the fuel, as well as "indirect" effects that are primarily associated with crop-based biofuels." About 75 percent of the GHG emissions from the well-to-wheel life of California Reformulated Gasoline and petroleum diesel are tailpipe emissions. Fuels and fuel blendstocks introduced into the California fuel system that have a CI higher than CARB benchmark Low carbon Fuel Standard generate deficits. Similarly, fuels and fuel blendstocks with CIs below the benchmark generate LCFS credits as a low-carbon fuel.(8)

Based upon the numbers presented in Phillips 66 Refinery's Rodeo Renewed Project Draft Environmental Impact Report, the calculatable and thus, post-project high refinery-level carbon intensity of renewable diesel is elevated far above the refinery's current average petroleum processing carbon intensity, on a per barrel basis and approach the total well-to-wheel carbon intensity of petroleum diesel refining. According to calculations presented in this appeal, renewable diesel should not qualify for LCFS credits. (8)

Specifically, for the Phillips 66, Refinery, this indicates that the Rodeo Renewed Project's carbon intensity for renewable diesel, 86.77 g/MJ will reach par with CARB's entire well-to-wheel petroleum diesel carbon intensity (Low Carbon Fuel Standard) benchmarks in the up-in-coming calendar years 2024 or 2025, at between 87.89 g/MJ or 86.64 g/MJ, respectively. (8)

Renewable Diesel refinery-level carbon intensity, is also nearly on par with the entire well-to-wheel life cycle assessment of California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and greatly exceeds it at the refinery-level. (According to CARB, "CARBOB makes up the petroleum fraction of California reformulated gasoline (CaRFG) before any fuel oxygenate is added; CARFG is essentially 90 percent CARBOB blended with 10 percent ethanol by volume.") (8)

For comparison of petroleum CARBOB carbon intensity with to the much higher renewable diesel carbon intensity findings presented in this appeal, "CARBOB CI is based on the 2010 average crude oil supplied to California refineries and average California refinery efficiencies. Production of CARBOB at all California refineries adds [only] 15g/MJ to the fuel cycle CI. (8)

Furthermore, the high refinery-level carbon intensity for renewable diesel is similar for the Marathon Renewable Project in Martinez. The refinery-level (midstream) Carbon Intensity scores of the Marathon and Phillips 66 Renewable Diesel projects are 77.11 g/MJ and 86.76 g/MJ, respectively, and are both well over three times the CARBOB refinery-level carbon intensity score, of 15 g/MJ.

The contrast with renewable diesel's high refinery-level carbon intensity is even greater for non-hydrogenated biodiesel, called fatty acid methyl ester FAME, such as made from used cooking oil, which has a very low refinery-level carbon intensity score of 11 g CO2/MJ. While renewable diesel can entirely substitute for 100% of petroleum diesel in diesel vehicles, FAME has poor flow in cold conditions, and is generally required to be blended with petroleum diesel at no more than a 7% FAME in the EU and 5% in the US, except for up to 20% for some fleets with modified engines. (8) Table 2.

CO2 GHG emissions from land-use changes (LUC) for both FAME biofuels and hydrotreated renewable diesel production are assumed at 30 g CO2e/MJ for soybean oil. When soybean oil's embedded 30 g/MJ LUC CO2 greenhouse gas is added to the projected refinery-level renewable diesel (HEFA) CO2 greenhouse gas emissions from both the Phillips 66 and Marathon refinery projects, these values significantly exceed the total CO2 greenhouse gas embedded in petroleum diesel (despite tailpipe CO2 emissions being discounted for renewable diesel, as for FAME).

Because of the general need for more intensive hydrocracking than Renewable Diesel, Sustainable Aviation Fuel made from hydrogenated vegetable oils and animal fats should have a possibly higher refinery-level carbon intensity score and thus, also not qualify of LCFS credit certification.

Table 1: Renewable diesel versus petroleum refining - per barrel hydrogen requirements

Hydrogen per barrel - scf /barrel		PRELIM	PRELIM +35%	Marathon	Phillips 66	Algal	HT	Karras	Average
		Petroleum	RD - theoretical	RD	RD	RD	RD	RD	RD
Renewable Diesel			2463.35	2497.45	2119.4	3062.5	2451	2270	2480.07
Petroleum		1824.7		655	1000				
Column		1	2	3	4	5	6	7	8
[Reference/footnote]		[6]		[1]	[2]	[4]	[3]	[5]	
		1	2	3	4	5	6	7	8

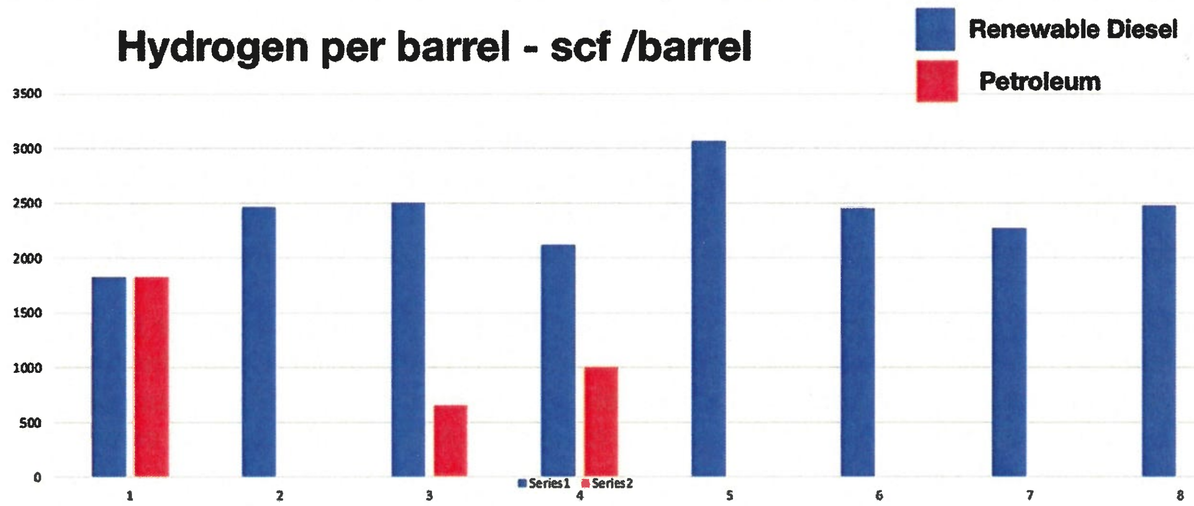
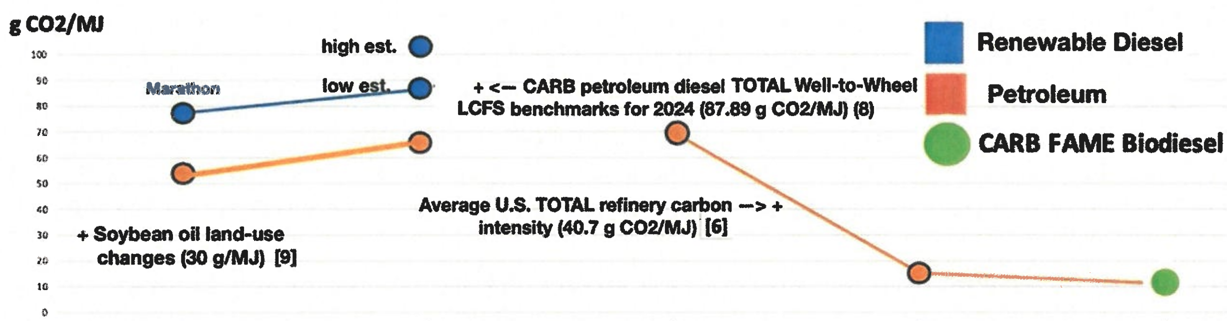


Table 2: Refinery level (midstream) carbon intensity / CO2 greehouse gas emissions only: : g CO2/MJ (kg CO2/bbl)

	MARATHON	PHILLIPS 66	PRELIM *	CARBOB **	CARB Biodiesel ***
Post project Renewable diesel - Marathon and Phillips 66:	77.11 (65.35)	86.77 (73.53)			
Petroleum Diesel* CA gasoline** Non-hydrotreated biofuels***			69.71 (58.97)	15	11
Pre-project (refinery-wide)	54.36 (46.07)	66.88 (56.68)			
	1	2	3	4	5
References and footnotes	(1) RD	(2) RD	(6) Petroleum Diesel	(8) Petroleum	(8) FAME: Fatty Acid
		Low estimate	API 14.96; S-3.35%	CA gasoline-No ethanol	Methyl Ester

Refinery-level only Carbon Intensity values



IV

To summarize, the true high refinery-level carbon intensity at a renewable diesel-configured refinery (as grams of CO2 per megajoule and equivalently, the kilogram per barrel CO2 emissions) have not been divulged in plain language, tabular form or graphically in either the Draft EIRs and Final EIRs for the Phillips 66 Refinery's Rodeo Renewed Project (and similarly for the Marathon Renewable Project). However, calculations can be performed on the numbers available in the Phillips 66 Draft EIR and other documents which show that renewable diesel, because it is so intensely hydrogenated, has a refinery-level carbon intensity value, on a per barrel- and per Megajoule-basis (as required by the California Air Resources Board), rivalling that of the heaviest globally-available crude oils.

So, what is currently being proposed in Contra Costa County, at the Phillips 66 Refinery, as well as the Marathon Refinery, are very expensive, publicly-funded, carbon-intensive renewable diesel projects, which are erroneously being promoted as sources of low-carbon fuel and so should be disqualified for California Low Carbon Fuel Standard Credits.

As the availability of used cooking oils and waste animal fat markets will be competitive and limited once multiple large refineries enter the renewable diesel business, the default principal feedstock is expected to be soybean oil in the reasonable future. At a yield of only 57 gallons of soybeans per acre, however, Phillips 66 alone could annually use up to 33,000 square miles of soybean acreage or nearly the size of the State of Indiana, for its expected 1.22 billion gallons of renewable diesel produced yearly. (10)

Financially, refinery biodiesel is being funded to the tune of up to $3.32 per gallon (according to Stratas Advisers, and depending on the feedstock). That could amount to up to $3 billion *yearly* given to Phillips 66 and $1.8 billion given to Marathon under false pretenses as producers of low carbon biofuels, which contradicts the massive increase in *per barrel* carbon intensity and global food security. (11)

Finally, the Phillips 66 DEIR states that the refinery's massive delayed coker and catalytic reformer will *not* be decommissioned in this project. Upon this appellant's email request to the refinery's senior engineer, regarding the company's purpose of this retention of equipment, the employee stated that these units' permits will be retained for the purpose of producing battery-grade petroleum coke (i.e., needle coke).

Accordingly, upon Project completion, the senior engineer replied that the retained delayed coker is intended to be used to coke FCC waste "slurry oil" obtained from other refineries in order to produce the battery-grade petroleum coke, Ostensibly, the FCC slutty oil would be a feedstock for subsequent calcining into graphite, at a yet unstated facility, which then would be used for carbon anodes for electrical vehicle batteries.

After the Rodeo Renewed Project is completed, this use of the delayed coker is consistent with the staff's statement that the refinery will no longer be using crude oil, which definitely leaves open the real possibility for a continuation of large-scale petroleum refining beyond the completion of the Rodeo Renewed Project. (12)

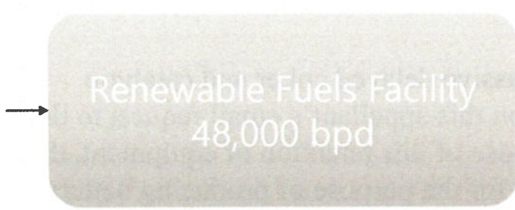
As FCC slurry oil is dirtier than the heavy FCC oils from which it is derived, it also contains more toxic heavy metals than the original FCC feedstock, being concentrated from both the FCC feedstock oil itself (with nickel and vanadium residues) and from the FCC spent catalyst (with additional nickel). The coker's product is always dumped from the bottom of the coker, in an open-air process and the tpractice of the Rodeo refinery is to store the petroleum coke in open piles.

Moreover, the light hydrocarbon (naptha) portion of the slurry oil feedstock will exit from a coker port and would likely be sent to the catalytic reformer to produce either branched hydrocarbons (for use as gasoline octane boosting agents) or more likely, if reconfigured, for the production of hydrogen (which could be used for additional on-site biofuel feedstock hydrotreating). This additional hydrogen can be used to produce more renewable diesel or to improve the conversion efficiency of the companies planned renewable diesel production or to make sustainable aviation fuel at some future point (which requires more hydrogen than renewable diesel production). (13)

The retention of Phillips 66's delayed coker and catalytic reformer and their stated plans for their coker, indicate that the refinery has intentionally retained the option for their continued fossil fuel refining and the possibility for producing significantly higher refinery-wide CO2 emissions than stated within the refinery's Draft Environmental Impact Report.

REFERENCES:

1) Marathon Renewable Project (Martinez CA; PowerPoint Presentation):



	Marathon Martinez	Refinery	Renewables	Delta Mtonnes/Yr
2	Capacity (mbpd)	160	48	
3	MPC GHG H2 Production (MTonnes/Yr)	448	687	239
4	AP GHG H2 Production (MTonnes/Yr)	230	275	45
5	GHG H2 Captured & Sold (MTonnes/Yr)	-56	-56	-
8	GHG All Other Combustion (MTonnes/Yr)	1547	239	-1,308
9	*Total Direct GHG w/ AP (MTonnes/Yr)*	*2169*	*1145*	*-1,024*

~ 60% reduction in GHG as part of project
Will continue to capture & sell 56,000 MT of CO2e

Marathon (calculations based on reference #1 and the DEIR's stated full refinery capacity of 125,000,000 scf/d):

REFINERY THROUGHPUT:

Pre-Project (Baseline):
Barrels (4-year avg. throughput; 161,000 bbl/d capacity): 129,000 bbl/d * 365 = 47,085,000 bbl/y

Decrease in total refinery throughput (4-year avg. throughput; 161,000 bbl/d capacity:
(129,000 – 48,000 = 81,000) / 129,000 = 0.6 = - 63% decrease in throughput

Pre-Project (Baseline):
Barrels (4-year avg. throughput; 161,000 bbl/d capacity): 129,000 bbl/d * 365 = 47,085,000 bbl/y

HYDROGEN PRODUCTION, REFINERY-WIDE:

Full refinery Hydrogen (H_2) capacity: 125000000 scf/d/ 423 scf/kg * 365 d/y * 9.3 kg CO_2/ kg H_2 / 1000 kg/MT = 1,003,102 MT/y

Hydrogen capacity utilization: 1,003,102 MT/y / 962,000 MT/y= 0.959 $\rightarrow$ 4% reduced from full refinery capacity

Post-project 962,000 MT/y from pre-project 678,000 MT kg/y

Pre-to-Post project hydrogen production increase (project total):
962 MT/y / 678 MT/y= 1.42 $\rightarrow$ + 42% (increase in total H_2-plant CO_2 emissions)

HYDROGEN PRODUCTION, PER BARREL:

Pre-project hydrogen per barrel:
678,000 MT kg/y / * 1,000 kg/MT / 365 d/y/ 9.3 gCO_2/gH_2 / 129,000 bbl/d* 423 scf/kg= 654.94 scf/bbl = 1.55 kgH_2/bbl

Post-project refinery-made hydrogen per barrel:
962,000 MT/y * 1,000 kg/MT / 9.3 / 365 / 48,000 bbl* 423scg/kg = 2497.46 scf/bbl = 5.9 kgH_2 /bbl

Pre-to-Post project hydrogen production increase (project total):
962 MT/y / 678 MT/y= 1.42 $\rightarrow$ + 42% (increase in total H_2-plant CO_2 emissions)

REFINERY CO_2 EMISSIONS AND PER BARREL CO_2 EMISSIONS:

Decrease in total refinery-wide CO_2:
1,145,000 / 2,169,000 = 0.5278 = - 53% (decrease in CO_2)

Pre-Project *total* annual refinery CO_2 (Carbon Intensity from GHG-to-bbl/y ratio and g CO_2/MJ):
2,169,000,000 (kg CO_2/y) / 47,085,000 bbl/y = 46.07 kg CO_2/bbl $\rightarrow$ 46.07 * 1.18 = 54.36 g CO_2/MJ

Post Project total refinery CO_2
Barrels: 48,000 bbl/d * 365 = 17,520,000 bbl/y
CO_2 Refinery-wide total: 1,145,000 mt/y * 1000 = 1,145,000,000 kg/y

Post-project Carbon Intensity (CO_2 GHG/y-to-bbl/y ratio and g CO_2/MJ):
1,145,000,000 kg/y / 17,520,000 bbl/y = 65.35 CO_2 kg/bbl
Carbon Intensity (g/MJ): 65.35 * 1.18= 77.11 g/MJ

Pre-to-Post project *per barrel* change in Carbon Intensity (Relative % - refinery-wide):

65.35 / 46.07 = 1.42 → +42% increase in CI

2a) **Rodeo Renewed Project (Rodeo CA; 80 K or 67 K barrels per day); Pre-Project (current 105 K bpd):**

Rodeo Renewed Project
Draft Environmental Impact Report

Table 4.8-2. Baseline Annual GHG Emissions (2019)[1]

Source Category	Baseline Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Refinery				
Ocean-going Vessels and Harbor Craft	15,137	0.15	0.93	15,418
Trucks	4,466	0.02	0.70	4,676
Rail	1,373	0.11	0.03	1,386
Facility Operations	1,333,341	91.96	11.74	1,338,911
Electricity	9,160	1.30	0.28	9,270
Rodeo Refinery Total	1,363,477	94	14	1,396,661
Air Liquide H_2 Plant	801,794	--	--	801,794
Santa Maria Site and Pipeline Sites				
Trucks	2,565	0.01	0.40	2,686
Rail	177	0.01	0.00	179
Facility Operations	171,765	17.30	1.43	172,571
Electricity	5,328	0.76	0.16	5,392
Total Statewide	2,345,107	111.62	15.68	2,352,284
Total within BAAQMD	2,165,272	93.54	13.69	2,171,455

1. 2019 is the CEQA baseline for this analysis for all sources except ocean-going vessels and harbor craft. For vessel emissions, an average of 2017 through 2019 was used.
Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant Site
Air Liquide CO_2e emissions assumed to be entirely CO_2 as the breakdown for CH_4 and N_2O is not available.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. It is expected to change to 25 and 298 respectively for reporting years 2021 and forward.

2b) Rodeo Renewed Project (Rodeo CA); Post-Project (completed):

Table 4.8-5. Total Annual Project Operational GHG Emissions

Source	Emissions (metric tons/yr)			
	CO_2	CH_4	N_2O	CO_2e
Rodeo Renewed Project Emissions				
Ocean Going Vessels and Harbor Craft	26,195	0.28	1.53	26,657
Rail	8,119	0.64	0.20	8,195
Trucks	2,720	0.00	0.43	2,847
Facility Stationary Sources	1,069,772	84.51	10.79	1,075,100
Electricity	1,180	0.41	0.09	2,889
Total Operational	**1,109,661**	**85.84**	**13.04**	**1,115,689**
Air Liquide H_2 Plant	1,031,689	--	--	1,031,689
Total Operational with Air Liquide	**2,141,350**	**85.84**	**13.04**	**2,147,378**
CEQA Impact Evaluation				
Baseline Emissions within BAAQMD	2,165,272	93.54	13.69	2,171,455
Project Minus CEQA Baseline				-24,077
Significance Threshold				10,000
Exceeds Threshold?				No
Statewide Impact Evaluation (informational only)				
Baseline Emissions Statewide	2,345,107	112	16	2,352,284
Project Minus Statewide Baseline				-204,905

Notes: Rodeo Refinery includes emissions from Rodeo Site and Carbon Plant.
Facility emissions GHG reporting for 2019 is based on 21 GWP for CH_4 and a 310 GWP for N_2O. Based on CARB reporting, it is expected to change to 25 and 298 respectively for reporting years 2021 and forward. Therefore, Project facility emissions are based on 25 GWP for CH_4 and a 298 GWP for N_2O.
The GHG emissions for the Air Liquide hydrogen plant are not reduced to reflect the offset provisions of the Settlement Agreement between ConocoPhillips Company and the Attorney General of California, dated September 10, 2007, and amended May 25, 2010.
Air Liquide CO_2e emissions assumed to be entirely CO_2 as breakdown for CH_4 and N_2O is not available.

2c) Air Liquide Hydrogen Plant H2 production; Table 15; Attachment B, Appendix B:

Stationary Source Table 15
Air Liquide Hydrogen Plant Emissions Summary
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

CAP and GHG Emissions

Scaling Method	Baseline Activity	Project Activity	Units	Pre-Project Emissions (tons/year)							Post-Project Emissions (tons/year)							Change in Emissions (tons/yr)						
				NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NO_x	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
Fuel Combustion	756	987	MMBTU/hr	17	0.010	0.95	1.1	3.6	3.5	--	22	0.013	1.2	1.4	4.7	4.6	--	5.1	0.0031	0.29	0.34	1.1	1.1	--
Hydrogen Production	93.26	120	MMSCF H2/day	--	--	--	--	--	--	801,794	--	--	--	--	--	--	1,031,689	--	--	--	--	--	--	229,895
			Total	17	0.010	0.95	1.1	3.6	3.6	801,794	22	0.013	1.2	1.4	4.7	4.6	1,031,689	5.1	0.0031	0.29	0.34	1.1	1.1	229,895

2d) Unit U110 Phillips 66 Hydrogen Plant H2 Production; table 13; Attachment B, Appendix B:

Stationary Source Table 13
Baseline and Post-Project TAC Emissions from Miscellaneous Project Sources
Phillips 66 Company - San Francisco Refinery
Rodeo, CA

Source ID	Description	Post-Project Status	Emission Type	Baseline Throughput		Post-Project Throughput		Baseline Emissions[1] (tons/year)							Post-Project Emissions[2] (tons/year)						
				Rate	Units	Rate	Units	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)	NOx	SO_2	CO	POC	PM_{10}	$PM_{2.5}$	GHGs (MT)
11	U240 B-201 Heater	Operational	Combustion	56	MMBtu/hr	33	MMBtu/hr	11	13	0.39	1.2	1.6	1.6	29,233	6.8	8.0	0.23	0.71	1.0	1.0	17,492
12	U240 B-202 Heater	Operational	Combustion	16	MMBtu/hr	24	MMBtu/hr	1.8	3.8	0.42	0.34	0.46	0.46	8,271	2.8	5.8	0.64	0.51	0.71	0.71	12,607
13	U240 B-301 Heater	Operational	Combustion	125	MMBtu/hr	93	MMBtu/hr	6.9	30	0.87	2.7	3.7	3.7	66,359	5.2	22	0.65	2.0	2.7	2.7	49,541
45	U246 B-801 A/B Heater	Operational	Combustion	62	MMBtu/hr	24	MMBtu/hr	1.4	0.12	0.82	0.26	0.81	0.81	28,384	0.52	0.046	0.32	0.10	0.31	0.31	10,922
437	Unit 110 Hydrogen Manufacturing Unit	Operational	Hydrogen Plant	12	MMScf/day	22	MMScf/day	--	--	--	--	--	--	100,368	--	--	--	--	--	--	177,642
438	U110 H-1 Furnace (H2 Plant Reforming)	Operational	Combustion	140	MMBtu/hr	225	MMBtu/hr	3.6	4.1	1.3	0.15	4.6	4.6	16,281	5.8	6.7	2.1	0.24	7.4	7.4	26,133

Notes:
1. Baseline emissions were obtained directly from the facility's 2019 BAAQMD Rule 12-15 Emissions Inventory.
2. Post-project emissions were estimated using baseline throughput and emissions and post-project projected rates.

Phillips 66 (calculations based on references #2a, 2b, 2c and 2d):

REFINERY THROUGHPUT; HYDROGEN PRODUCTION: REFINERY-WIDE: AND PER BARREL:

Pre-to-Post total refinery-wide project hydrogen production increase (total from Air Liquide and unit U110):
(120 mscf +22mscf) / (93 mscf + 12 mscf) = 142 mscf / 105 mscf = 1.35 → +35% (increase in H2 production)

Pre-project *per barrel* refinery-made hydrogen:
105,000,000 scf / 105,000 bbl/d = 1,000 scf/bbl [* 1/423 kg/scf] = 2.36 kg CO2/bbl

Post-project average *per barrel* refinery-wide hydrogen:
142,000,000 mscf / 67,000 bbl = 2119.40 scf/bbl [* 1/423kg/scf] = 5.01 kg CO2/bbl

Pre-to-post average *per barrel* refinery-wide hydrogen production ratio:
2119.40 mcf /1,000 scf = 2.12 → 120% increase

Pre-Project: *total* refinery CO2 (within BAAQMD area):
Barrels: 105,000 bbl/d * 365 = 38,300,000 bbl/y
CO2 Refinery-wide total: 2,171,000 mt/y = 2,171,000,000 kg/y

REFINERY CO2 EMISSIONS AND PER BARREL CO2 EMISSIONS:

Pre-Project: *total* refinery CO2:
Barrels: 105,000 bbl/d * 365 = 38,300,000 bbl/y
CO2 Refinery-wide total: 2,171,000 mt/y = 2,171,000,000 kg/y

Pre-Project (within the BAAQMD area) average refinery per bbl and per MJ CO2:
Carbon Intensity (CO2 GHG-to-BPY ratio): 2,171,000,000 kg/y / 38,300,000 bbl/y = 56.68 CO2 kg/bbl →
Carbon Intensity (g CO2/MJ) 56.68 * 1.18 = **66.88 g CO2/MJ**

Pre-Project (In-State) average refinery per bbl and per MJ CO2:
2,353,000,000 kg CO2/y / 38,300,000 bbl/y= 61.44 kg CO2/bbl
2,353,000,000 kg CO2/y / 38,300,000 bbl/y * 1.18 = 72.49 g CO2/MJ

Post Project: *total* refinery CO2 per barrel (low estimate):
Barrels: 80,000 bbl/d * 365 = 29,200,000 bbl/y
CO2 Refinery-wide total: 2,147,000 MT/y = 2,147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 kg/y / 29,200,000 bbl = 73.53 kg CO2/bbl
Carbon Intensity (g/MJ): 73.53 kg CO2/bbl * 1.18 = **86.77 g/MJ**

Post Project: *total* refinery CO2 per barrel (high estimate): clean fuels
Barrels: 67,000 bbl/d * 365 = 24,455,000 bbl/y
CO2 Refinery-wide total: 2,147,000 MT/y = 2.147,000,000 kg/y
Carbon Intensity (GHG-to-BPD ratio): 2,147,000,000 kg/y / 24,455,000 bbl/y = 87.79 CO2 kg/bbl
Carbon Intensity (g/MJ): 89.79 * 1.18 = **105.95 g/MJ**

Pre-to-Post project *per barrel change* in Carbon Intensity (Relative %):
a. 73.53 / 56.68 = 1.3 = **+ 30% → 30% increase in CI (low est.)**
b. 87.79 / 56.68 = = 1.55 = **+ 55% → 55% % increase in CI (high est.)**

3) **Hydrotreating in the production of green diesel.** Rasmus Egeberg, Niels Michaelsen, Lars Skyum and Per Zeuthen. *Haldor Topsøe.*

"As the reactions also consume large amounts of hydrogen (for a 100% renewable feed, a hydrogen consumption of 300–400 Nm^3/m^3 is not unusual), higher make-up hydrogen and quench gas flows are needed even when co-processing quite small amounts."

400 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) = 2451.61 scf/bbl (2451 / 423) = 5.79 kg/bbl * 9.3 = 53.85 CO2 kg/bbl (hydrogen-production only)

300 (Nm3/m3) = 400 (Nm3/m3) / 6.2 (bbl/MT) * 38 (scf/Nm3/m3) * 0.75 [(300nM3/M3) / 400 (NM3/M3)]= 1838.70 scf/bbl = (1838.7 / 423) = 4.34 kg/bbl = 40.36 CO2 kg/bbl (hydrogen-production only).

4) PATENTED HYDROCRACKER HYDROGEN USAGE FOR AGAEL BIOFUELS REFINING COMPARED TO SOY OIL. [Pub.No.:US2010/0297749A1 ARAVANIS et al. METHODS AND SYSTEMS FOR BIOFUEL PRODUCTION. Pub.Date: Nov.25,2010] (12)

For comparison of algael oil hydrorefining to soy oil and heavy petroleum hydrorefining, a patented algael biofuels protocol was described for hydrocracking, plus hydroisomerization and feedstock hydrotreating, of 80 barrels per day throughput using 245,000 scfd of hydrogen plant H2. The total hydrogen volume required for the described "Integrated Biofuels Refinery" for algael oil is 3,063 scf per barrel, which would place the algael fuel hydrocracker hydrogen consumption at the upper (heavy petroleum) end of the 1,000-3,000 scf per barrel range. Similar large- and small-size algael biofuels hydrorefinery configurations were described in the patent.

5) Changing Hydrocarbons Midstream. Karras, Greg. Community Energy Resource. Table 2. https://www.energy-resource.com/_files/ugd/bd8505_757a3372387d46358c74d958d158fcb5.pdf

Changing Hydrocarbons Midstream

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.

5) ENERGY STAR® Guide: ENERGY STAR is a U.S. Environmental Protection Agency Program for Energy and Plant Managers. (February 2015) https://www.energystar.gov/sites/default/files/tools/ENERGY_STAR_Guide_Petroleum_Refineries_20150330.pdf

The hydrocracker consumes energy in the form of fuel, steam and electricity (for compressors and pumps)…The reactions are carried out at a temperature of 500-750°F (290-400°C) and increased pressures of 8.3 to 13.8 Bar…The hydrocracker also consumes energy indirectly in the form of hydrogen. The hydrogen consumption is between 150 and 300 scf/barrel of feed (27-54 Nm^3/bbl) for hydrotreating and 1000 and 3000 scf /barrel of feed (180-540 Nm^3/bbl) for the total plant (Gary et al., 2007).

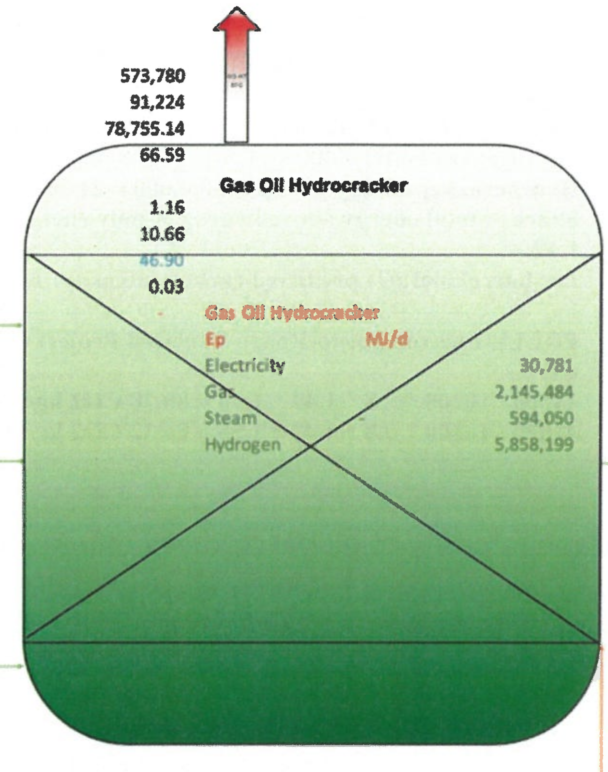
6) Petroleum Refinery Life Cycle Inventory Model (PRELIM) PRELIM v1.3. User guide and technical documentation. Jessica P. Abella et al. [Joule A. Bergerson] https://www.ucalgary.ca/sites/default/files/teams/477/prelim-v1.3-documentation.pdf
PRELIM 1.3 Hydrocracker with heavy, high-sulfur petroleum feedstock:
14.96 API and 3.35% Sulfur

Appeal of Contra Costa County Planning Commission's Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project.

charlesdavidson@me.com Hercules CA. 11 April 2022

Gas Oil HC Fuel Gas

Property	Units	
Vol Flow	bpd	573,780
Vol Flow	m^3/d	91,224
Mass Flow	kg/d	78,755.14
Sulphur	wt%	66.59
API gravity	°API	
Density	kg/m^3	1.16
Hydrogen	wt%	10.66
DHc	MJ/kg	46.90
Price	$/bbl	0.03
Allocation	Hydrogen Content Basis	-



Gas Oil Hydrocracker

Ep	MJ/d
Electricity	30,781
Gas	2,145,484
Steam	594,050
Hydrogen	5,858,199

Gas Oil Hydrocracker Feed

Property	Units	
Vol Flow	bpd	10,199.87
Vol Flow	m^3/d	1,621.65
Mass Flow	kg/d	1,566,698.34
Sulphur	wt%	3.35
API gravity		14.96
Density	kg/m^3	966.11
Hydrogen	wt%	11.18
MCR	wt%	-
Total hyd	kg/d	43,911.28
DHc	MJ/kg	39.29
Price	$/bbl	85.54
Allocation	Hydrogen Content Basis	-

PRELIM 1.3 heavy petroleum Hydrocracker (Gravity API 14.96 and Sulfur 3.35%):

Hydrocracker carbon intensity (CI) per day (total):
5.858,000 (H2)+2,145,000 (NG)+594,000 (steam)+31,000(e) = 8,628,000 MJ/d

Share of total hydrocracker energy (CI) above hydrogen-only energy:
8,628,000 MJ/ 5,858,000 MJ = 1.47 (47%)

Hydrogen required, per barrel:
44,000 kg H2/d / 10,200 bbl/d * 423 scf/kg H2 = 1824.70 scf /bbl

Hydrogen-plants daily CO2 emissions per day:
44000 kg H2/d * 1000 g/kg * 9.3 = 409,200,000 g CO2/d = 409,200 kg CO2 /d

Hydrocracker CO2 emissions per day (total):
44,000 kg H2/d * 1,000 g/kg * 9.3 gCO2/gH2 * 1.47 = 601,524,000 g CO2/d = 601,524 kg CO2 /d

PRELIM CO2 emissions, per barrel: (44,000 / 10,200 * 1.47 = 6.34) * 9.3 = **58.97 kg CO2 /bbl**
PRELIM Carbon Intensity: 601,524,000 g/d CO2 / 8,628,000 MJ/d = **69.71 g/MJ**

NOTE: CO2 mass-to-energy conversion factor (ratio): 69.71 g CO2/MJ /58.97 kg CO2/bbl → 1.18

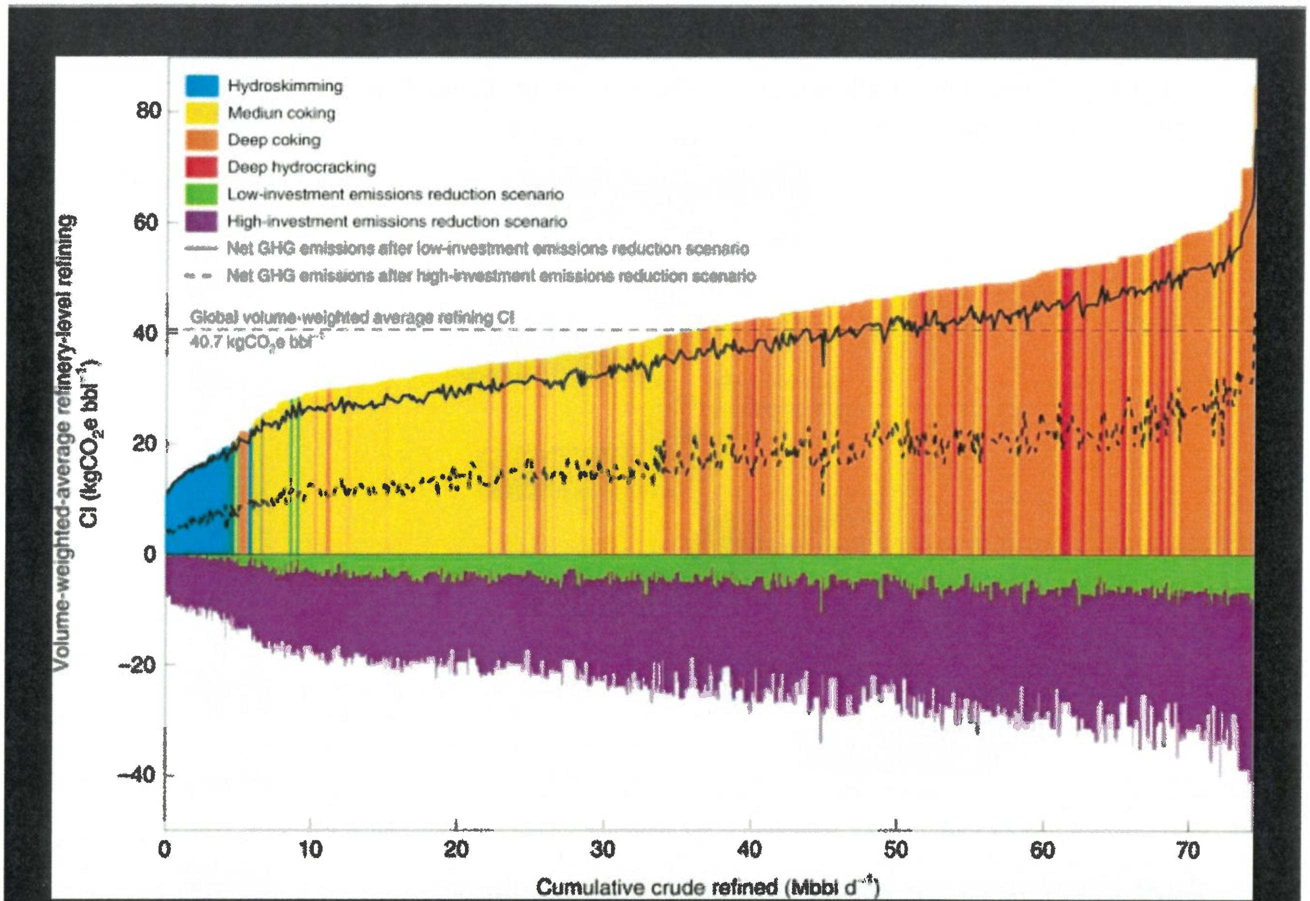
Phillips 66 predicted carbon intensity from +32% increase (w estimate; 80,000 bbl/d case):
58.97 **kg CO2 /bbl** * 1.32 = 77.84 **kg CO2 /bbl**
1.18 * 77.84 kg/bbl => **92.0 g/MJ.**

Phillips 66 predicted carbon intensity from +55% increase (High estimate; 67,000 bbl/d case):
1..18 * 91.4 kgCO2 /bbl => **108.05 g/MJ**

PRELIM petroleum-to-Marathon Renewable Project (+32% increase example; predicted Renewable Diesel CI)
Per barrel biofuels CO2 GHGs +32% inc. over petroleum:
Hydrogen per barrel: 44000 (H2/d) / 10200 (bbl/d) * 9.8 * 1.32 = 55.80 kg/bbl
Hydrocracker energy per day: 5858000 + 2145000 + 594000 + 31000 = 8628000
Share of total energy above hydrogen-only energy: 5858000 + 2145000 + 594000 + 31000 / 5858000 = 1.47
Per barrel biofuels predicted carbon intensity: 1.47 * 55.8 = 82.19 CO2 kg/bbl

PRELIM petroleum-to-Rodeo Renewed Project (high and low estimates; predicted Renewable Diesel CI)
44000 / 10200 * 9.8 * 1.47 * 1.30 = 80.78 CO2 kg/bbl (+30% low case est. per 80,000 bbl/d)
44000 / 10200 * 9.8 * 1.47 * 1.55 = 96.32 CO2 kg/bbl (+55% high case est. per 67,000 bbl/d)

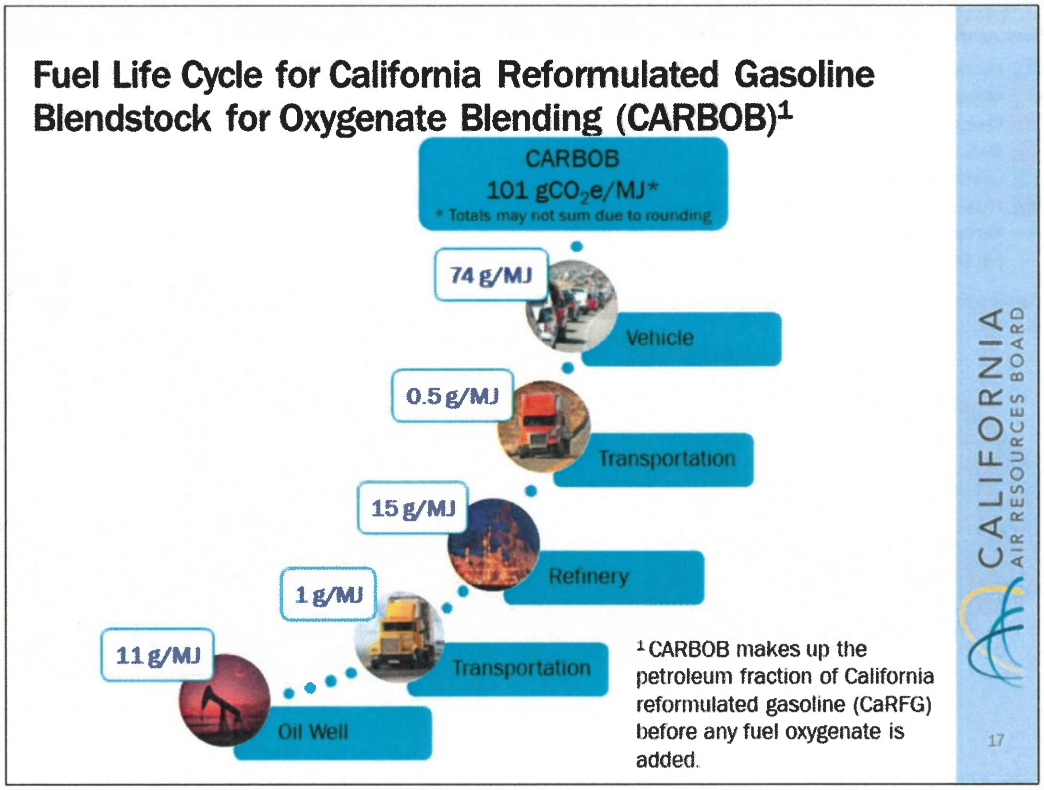
7) Carbon intensity of global crude oil refining and mitigation potential. Liang Jing et al. *Nature Climate Change* volume 10, pages 526–532 (J. Bergerson; 2020). The global-weighted carbon intensity at crude level is 10.1 – 72.1 kg CO2e/bbl, with a weighted average of 40.7 kgCO2e/kg.



Nature

Carbon intensity of global crude oil refining and mitigation potential | Nature Climate Change

8) Low Carbon Fuel Standards. [Basics] <https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf>


Fuel Life Cycle for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)[1]
CARBOB
101 gCO_2e/MJ*
* Totals may not sum due to rounding
74 g/MJ
Vehicle
0.5 g/MJ
Transportation
15 g/MJ
Refinery
1 g/MJ
Transportation
11 g/MJ
Oil Well
[1] CARBOB makes up the petroleum fraction of California reformulated gasoline (CaRFG) before any fuel oxygenate is added.
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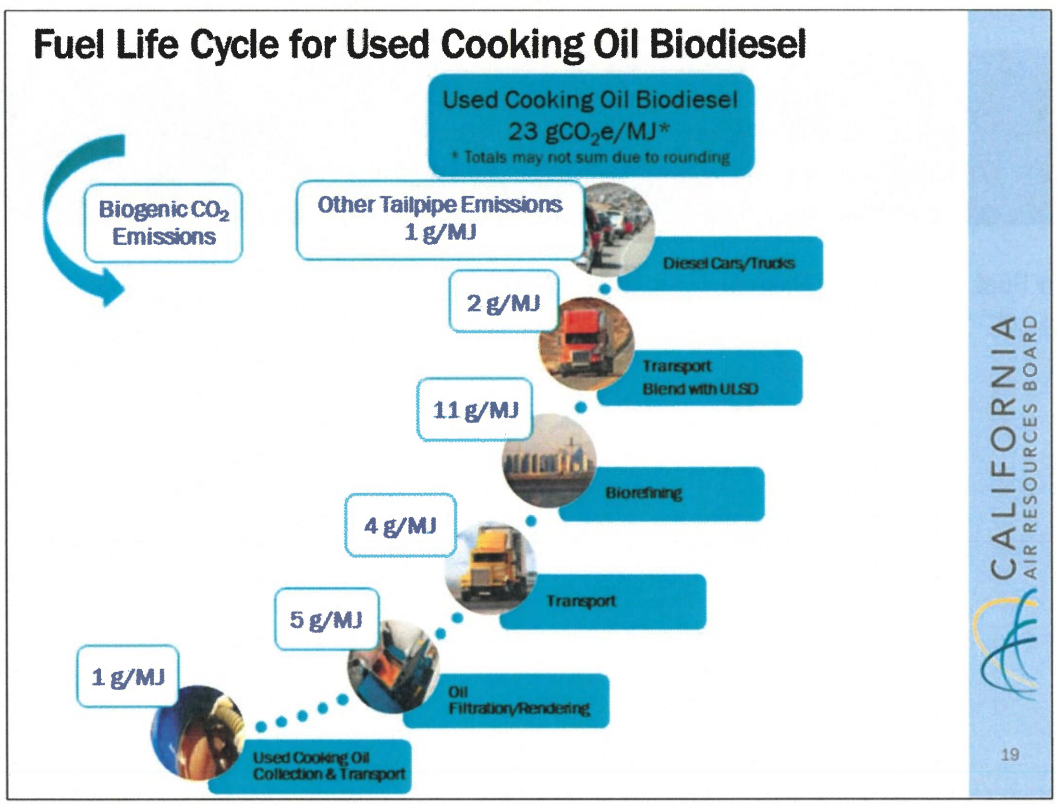
17


Fuel Life Cycle for Used Cooking Oil Biodiesel
Used Cooking Oil Biodiesel
23 gCO_2e/MJ*
* Totals may not sum due to rounding
Biogenic CO_2 Emissions
Other Tailpipe Emissions
1 g/MJ
Diesel Cars/Trucks
2 g/MJ
Transport
Blend with ULSD
11 g/MJ
Biorefining
4 g/MJ
Transport
5 g/MJ
Oil Filtration/Rendering
1 g/MJ
Used Cooking Oil Collection & Transport
CALIFORNIA AIR RESOURCES BOARD
19

9) Cradle-to-Grave Lifecycle Analysis of U.S. Light-Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current (2015) and Future (2025-2030) Technologies Elgowainy A et al. Argonne National Laboratory ANL/ESD-16-7 Rev. 1. (September 2016) <https://publications.anl.gov/anlpubs/2016/09/130244.pdf>

10) Biodiesel. S Sadaka. (FSA1050: DIVISION OF AGRICULTURE RESEARCH & EXTENSION University of Arkansas System). < https://www.uaex.uada.edu/publications/PDF/FSA-1050.pdf>

11) Overcapacity Looms as More and More US Refiners Enter Renewable Diesel Market. Stratas Advisors. (June 11, 2020) https://stratasadvisors.com/Insights/2020/06112020LCFS-RD-Investment

12) Post-Rodeo Renewed Project Delayed Coker permit retention for possible re-use:

Weinberg-Lynn, Nikolas<Nik.Weinberg-Lynn@p66.com>
Fri 7/23/2021 3:31 PM

To:

- Charles Davidson

Cc:

- Ursino, Adrienne <Adrienne.Ursino@p66.com>;
- Henry, Aimee <Aimee.M.Henry@p66.com>

Mr. Davidson,
Thanks for your participation in the July 22nd RMAC meeting and questions about the Rodeo Renewed project related to the future use of the Coker. Phillips 66 is retaining the coker permit for a possible future evaluation of producing battery-grade coke at the Rodeo site. Battery-grade coke is a key component in the manufacture of electric vehicle batteries (see graphic below) and Phillips 66 is a major global supplier. Feedstock for the coker would be slurry oil, which would be sourced from a different refinery. Once the Rodeo Renewed project is fully implemented, the Rodeo facility will not be permitted to process crude oil. Emissions from a potentially operating Coker will be accounted for in the EIR.

I appreciate your interest in the project and look forward to further discussion,

Nik Weinberg-Lynn
Manager, Renewable Energy Projects
O: (+1) 510.245.4567 | M: (+1) 310.923.1436
RDO-RM 205 | 1380 San Pablo Avenue | Rodeo, CA 94572

13) Catalytic reforming options and practices. Tom Zhou (Fluor Enterprises)
Frederik Baars (Fluor BV). (2010). [Design and practice in catalytic reforming is evolving to

meet refinery challenges, including lower gasoline pool benzene content and increased demand for hydrogen.] https://www.digitalrefining.com/article/1000479/catalytic-reforming-options-and-practices#.Ym7Iji-B034

[redacted]

From: Maureen Brennan [redacted]
Sent: Monday, May 2, 2022 5:15 PM
To: Clerk of the Board
Subject: Public comment Phillips66 May 3 meeting

Please do not approve this land use permit for Phillips 66 at this time. At the Planning Commission endorsement, they said this permit should be in tandem with a Community Benefits Agreement. The details of any actual agreement have yet to be negotiated. Please table this item until details of the agreement are in place.

There are many details of the draft EIR still unanswered. The hydrogen plant has been ignored, nor addressed by the Planning Commission. The Air Liquide plant is not capable of the planned increase of methane-fuel consumption, which risks explosion, and at the least, increased flaring events. Air Liquide has a history of yearly "unit upset" since it went online in 2009. Investigation of the capability of this plant facility should be a condition for approval before the permit is granted.

Phillips 66 has claimed an "extensive odor remediation program" with no details. Details of the plan should be a condition for approval before the permit is granted.

Rodeo is classified as a disadvantaged community by Contra Costa County. SB1000 requires Contra Costa County to integrate environmental justice into its General Plan. We here in Rodeo and Crockett have long experienced a disproportionate burden of pollution and health impacts, noise and odors.

Please table the current proposal until these items are addressed.

Thank you.

Maureen Brennan

Rodeo, CA

[redacted]

From: Nlouise Wolfe <[redacted]
Sent: Monday, May 2, 2022 5:30 PM
To: Clerk of the Board
Subject: Reject Renewable Fuels Project's EIRs

Dear Contra Costa Supervisor,
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points,** especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's [Declaration of Climate Emergency] commits to fight climate change and to protect the health and safety of vulnerable residents. These projects demand a more thorough EIR.
I am a concerned California resident who is very worried about this precedent setting initiative.
Thank You,

Nanlouise Wolfe
Santa Cruz

[redacted]

From: Kathy Kerridge <[redacted]
Sent: Monday, May 2, 2022 5:57 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

Please reject the land use permits and require additional EIRs for the Phillips 66 and Marathon renewable projects.

The EIRs were inadequate in many ways. They failed to account for cumulative impacts even though these projects are happening at the same time literally miles from one another. They didn't address the impacts of essentially burning food for fuel. Especially now with the breadbasket of Europe under attack we do now want people across the globe to starve so we can drive cars that could be powered by electricity or hydrogen produced through using renewable energy. The climate impacts of this conversion could be devastating if soy oil users turn to palm oil and then more rainforest is destroyed to produce palm oil. If peat bogs are converted it would be a climate bomb. Indonesia recently stopped the export of palm oil because of the impact it was having on food prices.

Please say no. If the refineries can't tell us what percentage of their feed stock will come from used cooking oils, ect. as compared to oil grown instead of food, we can only assume the worst.

Kathy Kerridge

Benicia, CA

[redacted]

From: gailsusangordon [redacted]
Sent: Monday, May 2, 2022 7:42 PM
To: Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc: Clerk of the Board
Subject: Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Gail Susan Gordon,
LMFT
San Pablo CA 94806

1000 Grandmothers for Future Generations

--

Gail Susan Gordon, LMFT, SEP

Licensed Marriage and Family Therapist

Somatic Experiencing Practitioner

1532 Solano Ave, Albany CA 94707

4980 Appian Way, Suite 206, El Sobrante CA 94806

gail@gailsusangordonmft.com

www.gailsusangordonmft.com

510-691-8123

[redacted]

From: Kathleen Rodgers [redacted]
Sent: Monday, May 2, 2022 7:48 PM
To: Karen Mitchoff; Supervisor Candace Andersen; Diane Burgis; District5; John Gioia
Cc: Clerk of the Board
Subject: Items D1 and D2, 5/3/22 BOS Meeting Agenda Public Comment

Dear Chair Mitchoff and members of the Board,

I am writing to urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects. Joint comments on the draft EIRs from multiple environmental groups included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points**, especially those relating to safety and land use. The final EIRs inadequately address the following concerns:

- *Failure to provide an adequate project description*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, and increased use of hydrogen*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts*
- *Failure to account for cumulative impacts*
- ***Failure to Comply with the CEQA Requirement to Respond to Public Comments***

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents. These projects conflict with that commitment. Please support a more thorough EIR for both proposed biofuel projects.

Kathleen Rodgers, San Pablo
CA

[redacted]

From: Woody Hastings <[redacted]
Sent: Monday, May 2, 2022 7:56 PM
To: Clerk of the Board
Subject: Comments of The Climate Center - Agenda items D1 and D2, May 3, 2022
Attachments: The Climate Center FEIR Comment - 5-3-22.docx.pdf

Dear Clerk of the Board,
Please see attached letter from The Climate Center regarding agenda items D1 and D2 on the Board's May 3, 2022 agenda. If you have any difficulty opening the attachment, please let me know, and please share the comments with the Board.
Thank you,

Woody Hastings
Energy Program Manager, The Climate Center
310-968-2757 (mobile/text)

Facebook | Twitter | Donate
Our mission: Deliver speed and scale greenhouse gas reductions, starting in California.

the climate center

Our mission
Deliver rapid greenhouse gas reductions at scale, starting in California.

Contact
www.theclimatecenter.org
P.O. Box 3785
Santa Rosa, CA 95402
707–525-1665

May 2, 2022

Contra Costa County Board of Supervisors
1025 Escobar Street, Martinez, CA 94553
Via Email: clerkoftheboard@cob.cccounty.us

Subject: Appeal of Contra Costa County Planning Commission Certification for the Final Environmental Impact Report for the Phillips 66 Rodeo Renewed Project (File No. LP20-2040) and for the Marathon biofuel refining conversion project

Dear Contra Costa County Supervisors,

On behalf of The Climate Center and its supporters in Contra Costa County and throughout California, I urge you to reject the land use permit and require additional environmental reviews for Phillips 66 and Marathon refinery biofuel conversion projects. The Climate Center is a climate and energy policy nonprofit which works for rapid greenhouse gas (GHG) reductions, starting in California.

Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments failed to address many of the concerns, especially those relating to safety and land use. The FEIRs inadequately address the following:

- Failure to consider climate impacts;
- Failure to comply with the CEQA requirement to respond to public comments;
- Failure to provide an adequate project description;
- Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen;
- Failure to account for impacts of burning food for fuel due to human food used as feedstock in biofuel refining;
- Failure to account for cumulative impacts.

Based on an analysis conducted by the Political Economy Research Institute in June 2021 "A Program for Economic Recovery and Clean Energy Transition in California," the transition to high road employment in the new clean energy economy can happen without extending the operation of these hazardous and polluting refineries. These refineries have also deleteriously impacted residents in nearby communities. A rejection by the Board of Supervisors to the proposals does not necessarily translate into lost jobs.

Lastly, Contra Costa County's [Declaration of Climate Emergency] commits to addressing the climate crisis in a way that protects the health and safety of vulnerable residents. To be consistent with the County's own climate emergency declaration, these projects demand a more thorough EIR.

Thank you for consideration of our concerns.

Sincerely,

Ellie M. Cohen
Chief Executive Officer
The Climate Center

[redacted]

From: Lisa argento martell [redacted]
Sent: Tuesday, May 3, 2022 4:30 AM
To: Clerk of the Board
Subject: Please reject the land use permit and EIR for renewable in Coco county!!

Dear Contra Costa Supervisors,
I am a concerned resident of Contra Costa county and live in Crockett.
I urge you to reject the land use permit and require additional EIR reviews for Phillips 66 and Marathon Refinery biofuels projects. Joint comments from multiple environmental groups on the draft EIRs included detailed, specific points about many technical aspects of the project. Responses to these comments **failed to address many of the specific points,** especially those relating to safety and land use. The FEIRs inadequately address the following concerns:

- *Failure to provide an adequate project description.*
- *Failure to account for safety and air pollution concerns from potentially increased operational upsets and hazards such as flaring, explosions, gas releases, increased use of hydrogen.*
- *Failure to account for impacts of burning food for fuel due to human food used as "feedstock" in biofuel production*
- *Failure to consider climate impacts.*
- *Failure to account for cumulative impacts.*
- **Failure to Comply with the CEQA Requirement to Respond to Public Comments**

The Contra Costa County's Declaration of Climate Emergency commits to fight climate change and to protect the health and safety of vulnerable residents. This whole project is replacing one dangerous and thoughtless industrial process with another. These projects demand a more thorough EIR.

Thank you for your attention and please forward my serious concerns.
Best regards,
Lisa Argento Martell
[redacted]
Crockett, CA 94525

[redacted]

From: lisa Sibony [redacted]
Sent: Tuesday, May 3, 2022 12:11 PM
To: Clerk of the Board
Subject: Reject Renewable Fuel Projects' EIRs

Dear Contra Costa Supervisors,

I urge you to reject the land use permits and require additional environmental impact reviews for the Phillips 66 and Marathon Refinery biofuels projects.

The Contra Costa County's **Declaration of Climate Emergency** commits to fighting climate change and to protecting the health and safety of vulnerable residents.These projects *must* have a more thorough EIR.

For the sake of the entire Bay Area, State of California and well beyond, please reject the permits and stop the refineries from causing more environmental damage.

Sincerely,
Lisa Sibony
Berkeley, CA

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Contra Costa County

Subject: Approve & Authorize to fully close a portion of Bixler Road on June 14, 2022 through August 2, 2022 from 7:00 a.m. through 5:00 p.m., Byron area.

RECOMMENDATION(S):

ADOPT Resolution No. 2022/132 approving and authorizing the Public Works Director, or designee, to fully close a portion of Bixler Road between Echo Place and Balfour Road, and Point of Timber Road east of Poe Drive, on June 14, 2022 through August 2, 2022 from 7:00 a.m. through 5:00 p.m., for the purpose of maintenance on existing Pacific Gas and Electric Company (PG&E) natural gas line system, Byron area. (District III)

FISCAL IMPACT:

No fiscal impact.

BACKGROUND:

PG&E seeks to close Bixler Road for the purpose of reconfiguring natural gas pipelines to eliminate the flow of gas northerly and excavation at Bixler and Balfour to demolish gas vaults and remove un-needed piping. The road closure is for public safety during construction activities and to expedite construction while removing existing facilities from service. Applicant shall follow guidelines set forth by the Public Works Department.

CONSEQUENCE OF NEGATIVE ACTION:

Applicant will be unable to close the road for planned activities.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Randolf Sanders (925) 313-2111

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

AGENDA ATTACHMENTS

Resolution No. 2022/132

MINUTES ATTACHMENTS

Signed: Resolution No. 2022/132

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/132

IN THE MATTER OF: Approving and Authorizing the Public Works Director, or designee, to fully close a portion of Bixler Road between Echo Place and Balfour Road, and Point of Timber Road east of Poe Drive, on June 14, 2022 through August 2, 2022 from 7:00 a.m. through 5:00 p.m., for the purpose of maintenance on existing Pacific Gas and Electric Company natural gas line system, Byron area. (District III)

RC22-3

NOW THEREFORE, BE IT RESOLVED that permission is granted to Pacific Gas and Electric Company to fully close Bixler Road between Echo Place and Balfour Road, and Point of Timber Road east of Poe Drive, except for emergency traffic, on June 14, 2022 through August 2, 2022 for the period of 7:00 am through 5:00 pm, subject to the following conditions:

1. Traffic will be detoured via traffic control plan reviewed by Public Works.

2. All signing to be in accordance with the California Manual on Uniform Traffic Control Devices.

3. Pacific Gas and Electric Company shall comply with the requirements of the Ordinance Code of Contra Costa County.

4. Provide the County with a Certificate of Insurance in the amount of $1,000,000.00 for Comprehensive General Public Liability which names the County as an additional insured prior to permit issuance.

5. Obtain approval for the closure from the Sheriff's Department, the California Highway Patrol and the Fire District.

6. Provide a press release, with point of contact information, to Public Works and local residents briefly explaining the anticipated work and duration.

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Randolf Sanders (925) 313-2111

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

C.1

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/132

IN THE MATTER OF: Approving and Authorizing the Public Works Director, or designee, to fully close a portion of Bixler Road between Echo Place and Balfour Road, and Point of Timber Road east of Poe Drive, on June 14, 2022 through August 2, 2022 from 7:00 a.m. through 5:00 p.m., for the purpose of maintenance on existing Pacific Gas and Electric Company natural gas line system, Byron area. (District III)

RC22-3

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2. All signing to be in accordance with the California Manual on Uniform Traffic Control Devices.

3. Pacific Gas and Electric Company shall comply with the requirements of the Ordinance Code of Contra Costa County.

4. Provide the County with a Certificate of Insurance in the amount of $1,000,000.00 for Comprehensive General Public Liability which names the County as an additional insured prior to permit issuance.

5. Obtain approval for the closure from the Sheriff's Department, the California Highway Patrol and the Fire District.

6. Provide a press release, with point of contact information, to Public Works and local residents briefly explaining the anticipated work and duration.

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Randolf Sanders (925) 313-2111

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M Boyd

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

Contra Costa County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Approve & Authorize to fully close a portion of Springbrook Road on June 1, 2022 through September 2, 2022, Walnut Creek area.

RECOMMENDATION(S):

ADOPT Resolution No. 2022/141 approving and authorizing the Public Works Director, or designee, to fully close a portion of Springbrook Road between Gilmore Court and Sherwood Way, on June 1, 2022 through September 1, 2022 from 7:00 a.m. through 5:00 p.m., for installation of East Bay Municipal Utility District water main and accompanying infrastructure (Infrastructure Renewal Project), Walnut Creek area. (District IV)

FISCAL IMPACT:

No fiscal impact.

BACKGROUND:

East Bay Municipal Utility District shall follow guidelines set forth by the Public Works Department to close Springbrook Road to through traffic for public safety during construction and to expedite the installation of the new water main. The location and alignment of the water mains within these roads and the existing pavement width does not allow for safely keeping the roads open to through traffic during working hours. The infrastructure Renewal Project consists of approximately 4,010' of 6", 8" & 12" water main, service transfer, hydrants and connections.

CONSEQUENCE OF NEGATIVE ACTION:

Applicant will be unable to close the road for planned activities.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

AGENDA ATTACHMENTS
Resolution No. 2022/141
MINUTES ATTACHMENTS
Signed: Resolution No. 2022/141

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/141

IN THE MATTER OF: ADOPT Resolution No. 2022/141 approving and authorizing the Public Works Director, or designee, to fully close a portion of Springbrook Road between Gilmore Court and Sherwood Way, on June 1, 2022 through September 1, 2022 from 7:00 a.m. through 5:00 p.m., for installation of East Bay Municipal Utility District water main and accompanying infrastructure (Infrastructure Renewal Project), Walnut Creek area. (District IV)

RC22-5

NOW, THEREFORE, BE IT RESOLVED that permission is granted to East Bay Municipal Utility District to fully close Springbrook Road between Gilmore Court and Sherwood Way, except for emergency traffic, local residents, US Postal Service, and garbage trucks, between June 1, 2022 through September 1, 2022 for the period of 7:00 a.m. through 5:00 p.m., subject to the following conditions:

1. Traffic will be detoured via traffic control plan reviewed by Public Works.

2. All signing to be in accordance with the California Manual on Uniform Traffic Control Devices.

3. East Bay Municipal Utility District shall comply with the requirements of the Ordinance Code of Contra Costa County.

4. Provide the County with a Certificate of Insurance in the amount of $1,000,000.00 for Comprehensive General Public Liability which names the County as an additional insured prior to permit issuance.

5. Obtain approval for the closure from the Sheriff's Department, the California Highway Patrol and the Fire District.

6. Provide a press release, with point of contact information, to Public Works and local residents briefly explaining the anticipated work and duration.

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Randolf Sanders (925) 313-2111

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

C.2

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:	/	
ABSENT:	/	
ABSTAIN:	/	
RECUSE:	/	

Resolution No. 2022/141

IN THE MATTER OF: ADOPT Resolution No. 2022/141 approving and authorizing the Public Works Director, or designee, to fully close a portion of Springbrook Road between Gilmore Court and Sherwood Way, on June 1, 2022 through September 1, 2022 from 7:00 a.m. through 5:00 p.m., for installation of East Bay Municipal Utility District water main and accompanying infrastructure (Infrastructure Renewal Project), Walnut Creek area. (District IV)

RC22-5

NOW, THEREFORE, BE IT RESOLVED that permission is granted to East Bay Municipal Utility District to fully close Springbrook Road between Gilmore Court and Sherwood Way, except for emergency traffic, local residents, US Postal Service, and garbage trucks, between June 1, 2022 through September 1, 2022 for the period of 7:00 a.m. through 5:00 p.m., subject to the following conditions:

1. Traffic will be detoured via traffic control plan reviewed by Public Works.

2. All signing to be in accordance with the California Manual on Uniform Traffic Control Devices.

3. East Bay Municipal Utility District shall comply with the requirements of the Ordinance Code of Contra Costa County.

4. Provide the County with a Certificate of Insurance in the amount of $1,000,000.00 for Comprehensive General Public Liability which names the County as an additional insured prior to permit issuance.

5. Obtain approval for the closure from the Sheriff's Department, the California Highway Patrol and the Fire District.

6. Provide a press release, with point of contact information, to Public Works and local residents briefly explaining the anticipated work and duration.

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M Boyd

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Bob Hendry -Engineering Services, Chris Lau - Maintenance, CHP, Sheriff - Patrol Division Commander

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Contra Costa County

Subject: Prohibit stopping, standing, or parking at all times on a portion of Arlington Boulevard (Road No. 1061B), East Richmond Heights area.

RECOMMENDATION(S):

ADOPT Traffic Resolution No. 2022/4520 to prohibit stopping, standing, or parking at all times on the east side of Arlington Boulevard (Road No. 1061B), beginning 50 feet north of the south curb line prolongation of Claremont Avenue (Road No. 1065A) and extending northerly a distance of 25 feet, as recommended by the Public Works Director, East Richmond Heights area. (District I)

FISCAL IMPACT:

No fiscal impact.

BACKGROUND:

A resident on Arlington Boulevard contacted the Transportation Engineering Division stating concern with sight line obstruction of northbound traffic and difficulty entering safely onto Arlington Boulevard from his private driveway. Traffic Engineering staff responded by researching collision history and conducting a site visit soon after. Although reported collisions did not present themselves, the existing roadway width is too narrow to accommodate through traffic and a parked vehicle at this location. Due to this narrow roadway condition at this bend in the road, staff recommends prohibited parking on a small portion of Arlington Boulevard. This action will deter drivers from parking and partially blocking the northbound travel lane, leading motorists into the southbound lane of travel.

CONSEQUENCE OF NEGATIVE ACTION:

Parking will remain unrestricted at this location.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Monish Sen, 925.313.2187

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc:

AGENDA ATTACHMENTS
Traffic Resolution 2022/4520
MINUTES ATTACHMENTS
Signed: Traffic Resolution No. 2022/4520

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

Adopted this Traffic Resolution on May 3, 2022 by the following vote:

AYES:

NOES:

ABSENT:

TRAFFIC RESOLUTION NO. 2022/4520

ABSTAIN:

Supervisorial District I

SUBJECT: Prohibit stopping, standing, or parking at all times on a portion of Arlington Boulevard (Road No. 1061B), East Richmond Heights area.

The Contra Costa County Board of Supervisors RESOLVES that:

Based on recommendations by the County Public Works Department's Transportation Engineering Division, and pursuant to County Ordinance Code Sections 46-2.002 - 46-2.012, the following traffic regulation is established:

> Pursuant to Section 22507 of the California Vehicle Code, stopping, standing, or parking is hereby declared to be prohibited at all times on the east side of Arlington Boulevard (Road No. 1061B), East Richmond Heights area, beginning 50 feet north of the south curb line prolongation of Claremont Avenue (Road No. 1065A) and extending northerly a distance of 25 feet.

I hereby certify that this is a true and correct Copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED:_______________________________________
Monica Nino, Clerk of the Board of Supervisors and County Administrator

By _______________________________________, Deputy

MS:sr

Orig. Dept: Public Works (Traffic)
Contact: Monish Sen, 313-2187

cc: California Highway Patrol
Sheriff Department

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

Adopted this Traffic Resolution on May 3, 2022 by the following vote:

AYES: Gioia, Andersen, Burgis, Mitchoff, Glover

NOES: None

ABSENT: None

ABSTAIN: None

TRAFFIC RESOLUTION NO. 2022/4520
Supervisorial District I

SUBJECT: Prohibit stopping, standing, or parking at all times on a portion of Arlington Boulevard (Road No. 1061B), East Richmond Heights area.

The Contra Costa County Board of Supervisors RESOLVES that:

Based on recommendations by the County Public Works Department's Transportation Engineering Division, and pursuant to County Ordinance Code Sections 46-2.002 - 46-2.012, the following traffic regulation is established:

> Pursuant to Section 22507 of the California Vehicle Code, stopping, standing, or parking is hereby declared to be prohibited at all times on the east side of Arlington Boulevard (Road No. 1061B), East Richmond Heights area, beginning 50 feet north of the south curb line prolongation of Claremont Avenue (Road No. 1065A) and extending northerly a distance of 25 feet.

I hereby certify that this is a true and correct Copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022
Monica Nino, Clerk of the Board of Supervisors and County Administrator

By Stacey M. Boyd, Deputy

MS:sr

Orig. Dept: Public Works (Traffic)
Contact: Monish Sen, 313-2187

cc: California Highway Patrol
Sheriff Department

Contra
Costa
County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Reimbursement Agreement with IPT Richmond DC III LLC for the Chesley Avenue Traffic Calming Improvements, North Richmond area.

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Public Works Director, or designee, to execute a reimbursement agreement with IPT Richmond DC III LLC in the amount of $267,950.65 for offsite roadway improvements that serve developments within the North Richmond Area of Benefit, in accordance with the County's Traffic Fee Credit and Reimbursement Policy and Government Code Sections 66484 through 66489, North Richmond area. (District I)

DETERMINE that the County's reimbursement for the improvements excludes dedications, setbacks, improvements, and traffic mitigation measures required of IPT Richmond DC III LLC's development by ordinance or local standards.

FISCAL IMPACT:

100% North Richmond Area of Benefit funds.

BACKGROUND:

Under the County's Traffic Fee Credit and Reimbursement Policy, approved by the Board of Supervisors on June 5, 2007 ("Reimbursement Policy"), a developer that constructs offsite transportation improvements meeting certain requirements may receive a credit for the cost of those improvements toward the amount of area of benefit fees the developer is required to pay for its development project.

On May 8, 2018, the Board of Supervisors approved Development Plan (DP) 14-3041 authorizing IPT Richmond DC III, LLC ("Developer") to construct one warehouse building totaling 492,873 square feet, located at 500 Pittsburg Avenue, in the North Richmond area. Condition of Approval (COA) No. 47 in the development plan required the Developer to construct an offsite truck traffic

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Jeff Valeros, 925.313.2031

cc:

BACKGROUND: (CONT'D)

calming improvement within any of several specified roadway corridors, one of which is Chesley Avenue. In connection with the approval of DP 14-3041, the Board of Supervisors adopted a mitigated negative declaration to satisfy the requirements of the California Environmental Quality Act.

The North Richmond Area of Benefit (NRAOB) project list includes, as one of its projects, the installation of a speed table and related roadway improvements on Chesley Avenue, between Fred Jackson Way and the Union Pacific Railroad to deter semitrucks from taking this residential route (“Project NR 15”). The Developer selected Project NR 15 to meet the Developer’s obligations under COA No. 47. The construction of the project included a speed table in the form of a raised crosswalk, required pavement reconstruction on the 5 th and 6th Street intersections with Chesley Avenue, and a bulb out and ADA curb ramp on the 6th Street intersection. Public Works staff have confirmed that all of this work is within the scope of Project NR 15 in the NRAOB fee program.

The offsite transportation improvements that comprise Project NR 15 will serve transportation needs within the NRAOB beyond those attributed to the Developer’s development. Public Works Department staff have determined that the Developer-constructed offsite improvements meet the requirements of the Reimbursement Policy and, therefore, are eligible for credit or reimbursement toward the Developer’s NRAOB fee obligation. Public Works staff also determined that, although the Developer’s cost to construct Project NR 15 ($267,950.65) exceeds the project cost listed in the NRAOB development program report, the costs the Developer incurred were reasonable given increases in construction costs. Public Works staff have confirmed that those costs were necessarily incurred by the Developer to complete Project NR 15. Because the Developer has already paid all of its NRAOB fees for the development ($2,660,251), the cost of the Project NR 15 improvements ($267,950.65) will be reimbursed to the Developer from NRAOB fee revenues under the reimbursement agreement.

CONSEQUENCE OF NEGATIVE ACTION:

If the reimbursement agreement is not approved, the developer will not be reimbursed for the cost of constructing the offsite improvements.

ATTACHMENTS

Reimbursement Agreement

Exhibit A

Exhibit B

NR AOB Nexus Study Proj. List

CONTRA COSTA COUNTY
PUBLIC WORKS DEPARTMENT

REIMBURSEMENT AGREEMENT

1. PARTIES. Effective ________________________, the County of Contra Costa, a political subdivision of the State of California, (hereinafter "COUNTY"), IPT Richmond DC III LLC, a Delaware limited liability company, (hereinafter "DEVELOPER") mutually agree as follows:

2. INTRODUCTION.

   A. DEVELOPER is developing an industrial parcel under Development Plan (DP) 14-3041 (within North Richmond Area of Benefit) (hereinafter, "Development"). The Development is within the jurisdiction of the County of Contra Costa. To satisfy COUNTY's conditions of approval for said Development, DEVELOPER must install a portion of the road improvements ("Road Improvements") identified in the adopted Development Program Report for the North Richmond Area of Benefit.

   B. COUNTY has adopted a Traffic Fee Credit and Reimbursement Policy for the North Richmond Area of Benefit (hereinafter, the "Policy"), the terms of which are incorporated herein by reference. A copy of said Policy is attached hereto as Exhibit A. Capitalized terms not otherwise defined herein shall have the meaning ascribed to them in the Policy.

   C. DEVELOPER has paid the full amount of fees – $2,660,251 – required for the Development under the Area of Benefit fee ordinance for said Area of Benefit, Ordinance No. 2017-22 (hereinafter, "Ordinance"). Therefore, the costs to be incurred by DEVELOPER for installation of the Road Improvements will exceed DEVELOPER's area of benefit fee obligation under the Ordinance.

   D. Pursuant to Paragraphs II and V of the Policy, following DEVELOPER's installation of the Road Improvements, and after COUNTY accepts the Road Improvements as complete, DEVELOPER will be entitled to a reimbursement of DEVELOPER's Eligible Costs to install the Road Improvements, which exceed DEVELOPER's area of benefit fee obligation under the Ordinance.

   E. To allow for reimbursement to DEVELOPER of its Eligible Costs of installing the Road Improvements, DEVELOPER and COUNTY wish to enter into this Reimbursement Agreement (hereinafter "Agreement") pursuant to the Policy.

3. AUTHORITY. This Agreement is authorized by and entered into pursuant to Government Code sections 66485 through 66489.

4. TERMS. In accordance with the terms of this Agreement, the Policy, and COUNTY's above mentioned Development Program Report, COUNTY will reimburse DEVELOPER for the Eligible Costs to install the Road Improvements that DEVELOPER is required to install under the conditions of approval for DP 14-3041.

5. ELIGIBLE COSTS. The Road Improvements and DEVELOPER's Eligible Costs are outlined on Exhibit "B", attached hereto and incorporated herein by reference.

6. DEDICATION OF RIGHT OF WAY. Any Right of Way containing the Road Improvements covered by this Agreement shall be offered for dedication to the COUNTY.

7. CONFORMANCE TO PLANS AND SPECIFICATIONS. The Road Improvements covered by this Agreement shall be installed in conformance with the plans and specifications prepared by DEVELOPER and approved by COUNTY.

8. ACCEPTANCE OF ROAD IMPROVEMENTS. COUNTY is under no obligation to perform under this Agreement unless and until the Road Improvements are accepted as complete by COUNTY; provided, however, that, COUNTY shall process acceptance documentation (Notice of Completion and Acceptance) within a reasonable time after the later of the date of COUNTY's final inspection, or the date upon which the DEVELOPER returns to COUNTY the appropriate signed acceptance documentation. COUNTY shall be under no obligation to accept the Road Improvements as complete unless COUNTY, in its sole reasonable discretion, determines both of the following requirements have been satisfied:

   A. The Road Improvements conform to the requirements of this Agreement and the conditions of approval for the Development; and

   B. All punchlist work has been satisfactorily completed..

9. HOLD HARMLESS. For a period of three years from the date of County's acceptance of the Road Improvements, DEVELOPER shall defend, indemnify, save and hold COUNTY and its governing body, officers, agents and employees absolutely free, clear, and harmless from any claims, actions, or costs arising from any property and/or rights acquisition which may be necessary hereunder, or arising from any and all damage to property, injury to persons, including death, or any other type of liability arising as a result of DEVELOPER's installation of the Road Improvements required by the conditions of approval for the Development.

10. NON-RESPONSIBILITY OF COUNTY. The installation of the Road Improvements covered by this Agreement is the sole responsibility of DEVELOPER, except for the normal inspection provided by the COUNTY. COUNTY assumes no responsibility whatsoever for construction procedures and methods utilized by DEVELOPER in constructing the Road Improvements; however, DEVELOPER shall comply with the plans and specifications and all applicable codes.

11. PAYMENT. Payment terms and reimbursement procedures are set forth in Exhibit "A", except that the first payment will not be made until DEVELOPER submits to COUNTY acceptable evidence that DEVELOPER has paid for installation of the Road Improvements covered by this Agreement.

12. TERMINATION. This Agreement shall remain in effect either (1) for the time as provided in Section V.B. of Exhibit "A" or (2) until DEVELOPER has been reimbursed for the total eligible reimbursement amount, whichever first occurs. Non-submittal of the acceptable evidence of payment required by Section 11 shall not result in an extension of the termination date.

12. NO OTHER RECOURSE AGAINST COUNTY. This Agreement constitutes the total statement of rights between COUNTY and DEVELOPER concerning payment or reimbursement for costs of installing the Road Improvements exceeding the required Area of Benefit Fee Obligation.

[Signatures on Following Page]

COUNTY

Brian M. Balbas
Public Works Director

By ______________________________

Exhibit "A" - Traffic Fee Credit and Reimbursement Policy

Exhibit "B" - Preliminary Cost Estimates

DEVELOPER*

By: BTC II Holdco LLC
Member, IPT Richmond DC III LLC

By: Build-To-Core Industrial Partnership II LP Manager, BTC II Holdco LLC

By: IPT BTC II GP LLC
General Partner, Build-To-Core Industrial Partnership II LP

By: IPT Real Estate Holdco LLC
Member, IPT BTC II GP LLC

By: BCI IV Portfolio Real Estate Holdco LLC
Member, IPT Real Estate Holdco LLC

By: BCI IV Operating Partnership LP
Member, BCI IV Portfolio Real Estate Holdco LLC

By: Black Creek Industrial REIT IV Inc.
General Partner, BCI IV Operating Partnership LP

By ______________________________

Name: Chris Sanford

Title: Principal

Taxpayer I.D. # 37-1859857

* If Developer is a corporation, two officers must sign. The first must be the chairman of the board, president or any vice president; the second must be the secretary, assistant secretary, chief financial officer or any assistant treasurer. (Corp. Code § 313; Civ. Code, § 1190.) If Developer is a limited liability company, Developer shall sign in the manner required of corporations, or by two managers, or by one manager, pursuant to the articles of organization (see Corp. Code, §§ 17151, 17154, 17157.) If Developer is a partnership, any authorized partner may sign. Signatures by Developer must be notarized.

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT **CIVIL CODE § 1189**

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)
County of Orange)

On April 12, 2022 before me, Julie L. Dennis, Notary Public,
Date *Here Insert Name and Title of the Officer*

personally appeared Chris Sanford
Name(s) of Signer(s)

who proved to me on the basis of satisfactory evidence to be the person~~(s)~~ whose name~~(s)~~ is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature~~(s)~~ on the instrument the person~~(s)~~, or the entity upon behalf of which the person~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

JULIE L. DENNIS
Notary Public - California
Orange County
Commission # 2341653
My Comm. Expires Jan 16, 2025

Signature Julie L. Dennis
Signature of Notary Public

Place Notary Seal Above

OPTIONAL

Though this section is optional, completing this information can deter alteration of the document or fraudulent reattachment of this form to an unintended document.

Description of Attached Document

Title or Type of Document: ______ Document Date: ______
Number of Pages: ______ Signer(s) Other Than Named Above: ______

Capacity(ies) Claimed by Signer(s)

Signer's Name: ______
☐ Corporate Officer — Title(s): ______
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______
Signer Is Representing: ______

Signer's Name: ______
☐ Corporate Officer — Title(s): ______
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______
Signer Is Representing: ______

EXHIBIT A

TRAFFIC FEE CREDIT AND REIMBURSEMENT POLICY

Adopted ___________

This Traffic Fee Credit and Reimbursement Policy ("Policy"), adopted by the Contra Costa County Board of Supervisors, shall be used to determine credits and reimbursements of Area of Benefit Traffic Fees.

I. TERMS AND DEFINITIONS

The terms set forth in this paragraph, as used in this Policy, are defined as follows:

A. Development Program Report: The report adopted by the Board of Supervisors for an Area of Benefit, identifying road improvements needed to serve that Area of Benefit, the estimated costs of those road improvements and recommended traffic fees.

B. Area of Benefit Traffic Fee Ordinance: The ordinance adopted for an Area of Benefit pursuant to Government Code section 66484 and Division 913 of the Contra Costa County Ordinance Code, establishing the traffic fees necessary to complete construction of the road improvements in that Area of Benefit.

C. Area of Benefit Fee Obligation: The traffic fee due on a development, as determined from the Area of Benefit Traffic Fee Ordinance.

D. Improvement Costs: The cost of installing road improvements identified in the Development Program Report for an Area of Benefit.

E. Eligible Costs. The portion of Improvement Costs eligible to be applied as credits against the Area of Benefit Fee Obligation or reimbursed to a developer, as more particularly described in Paragraph III of this Policy.

F. Onsite Road Improvements: Public road improvements required within the boundaries of a development and the first twenty feet (20) of pavement widening of the public road(s) along the frontage of the development.

G. Offsite Road Improvements: Public road improvements identified in the Development Program Report that are required outside the boundaries of a development, beyond the first twenty (20) feet of pavement widening of the public road(s) along the frontage of the development.

H. Credit: A deduction from a developer's Area of Benefit Fee Obligation for which a developer may be eligible if the developer has incurred Eligible Costs to install Offsite Road Improvements.

I. Reimbursement: A payment for which a developer may be eligible if Eligible Costs exceed the developer's Area of Benefit Fee Obligation.

II. GENERAL

Installation of road improvements that are required as a condition of approval of development can be very costly and, in many cases, benefits other properties within an Area of Benefit. An Area of Benefit Traffic Fee Ordinance distributes the fee for these road improvements to all parcels within the Area of Benefit in proportion to the estimated benefits they will receive from the improvements. The ordinance becomes operative with respect to a specific parcel of land upon a request to develop or improve that parcel. The Area of Benefit Fee Obligation is limited to the fee due and is payable as a condition of approval of a final map or issuance of a building permit.

When a condition of development requires a developer to construct Offsite Road Improvements, the developer may be entitled to a credit against the Area of Benefit Fee Obligation. When a condition of development requires the construction of Offsite Road Improvements with a cost in excess of the Area of Benefit Fee Obligation, a portion of the excess cost may be eligible for reimbursement.

III. ELIGIBLE COSTS

Eligible Costs may be applied as a credit against the Area of Benefit Fee Obligation and, to the extent Eligible Costs exceed the Area of Benefit Fee Obligation, reimbursed to the developer. Eligible Costs are as follows:

A. Actual costs of construction of Offsite Road Improvements, including but not limited to costs of grading, paving, erosion control, installation of fencing, walls and traffic signals, permit fees and public agency inspection fees. Actual costs shall be determined based on invoices submitted by the developer to the Public Works Department.

B. Costs of design of Offsite Road Improvements, including civil and geotechnical engineering, traffic consulting and traffic signal design, which shall equal the lesser amount of either (1) the developer's actual costs of design, determined based on invoices submitted by the developer to the Public Works Department; (2) 14 percent of the actual costs of construction of the Offsite Road Improvements; or (3) 14 percent of the lowest of three independent bids submitted by the developer and approved by the Public Works Department.

C. Costs of administration of contracts related to Offsite Road Improvements, which shall equal the lesser amount of (1) the developer's actual costs of administration of contracts, determined based on invoices submitted by the developer to the Public Works Department; (2) 14 percent of the developer's actual costs of construction of the Offsite Road Improvements; or (3) 14 percent of the lowest of three independent bids submitted by the developer and approved by the Public Works Department.

D. Costs of acquisition of right-of-way needed for the construction of Offsite Road Improvements, which shall equal the lesser amount of (1) the developer's actual costs of acquisition or (2) fair market value of the right-of-way. Notwithstanding the foregoing, if the developer owns or possesses any other interest in the parcel or parcels of real property containing the right-of-way, costs of acquisition of the right-of-way shall not be applied as a credit or reimbursed to the developer.

Notwithstanding anything to the contrary herein, the County reserves the right to reject any or all of the developer's bids, invoices and/or any other proposed value of said Eligible Costs and to calculate said costs using then current prices as determined by Public Works staff.

If the developer elects to construct more costly road improvements than those shown on the adopted Development Program Report, the County reserves the right to calculate Eligible Costs using the then current prices for only the road improvements shown on the adopted Development Program Report, as determined by Public Works staff.

IV. CREDIT

When a condition of development requires the developer to construct Offsite Road Improvements, Eligible Costs may be applied as a credit against the Area of Benefit Fee Obligation.

V. REIMBURSEMENT

A. Where Eligible Costs exceed the Area of Benefit Fee Obligation, the developer, upon entering into a reimbursement agreement with the County, will be eligible for reimbursement of the amount of Eligible Costs that is in excess of the Area of Benefit Fee Obligation.

B. The reimbursement is subject to the following limitations:

1. Reimbursements will be paid only from fees collected pursuant to an Area of Benefit Traffic Fee Ordinance.

2. If more than one reimbursement agreement is in effect in an Area of Benefit, the reimbursement payment under each agreement will be based on the ratio of each agreement's original amount to the total original amount of all outstanding reimbursement agreements.

3. The County reserves the right to utilize not more than 80 percent of the Area of Benefit traffic fees collected annually, on a fiscal year basis, for the purpose of making reimbursement payments.

4. Reimbursement payments will be made quarterly, except that, during any quarter the County reserves the right not to make said payments if the amount of available funds to be disbursed is less than $5,000.00.

5. Reimbursement agreements will remain in effect for a base period of ten years (forty quarters). The first quarter shall be the one following the

quarter in which the first reimbursement payment is made. The developer shall forfeit any outstanding balance owed at the end of the ten years if 80 percent or more of the money has been reimbursed. If at the end of the ten years, less than 80 percent of the money has been reimbursed, the agreement will be extended for five years. If after a period of five years the developer has not been reimbursed 80 percent of the amount due, the agreement shall be extended for another period of five years. Any remaining balance owed after twenty years shall be forfeited.

VI. SPECIAL CONDITIONS

From time to time, project-specific situations may arise that, in the judgment of County staff, require special terms to be added to the standard reimbursement agreement. Such terms may address matters that are not specifically covered in the Policy or may be exceptions to the Policy. Such terms may be incorporated into the reimbursement agreement to be executed by the developer and approved by the Board of Supervisors.

VII. APPLICABILITY

Upon adoption for a particular Area of Benefit, this Policy will be the basis for all subsequent reimbursement agreements in that Area of Benefit. This Policy will not alter any reimbursement agreement executed pursuant to a different policy.

H:\Final\PW\TrafficPolicy.5.7.07.wpd

ITP Richmond DC III LLC
Chesley Avenue Summary
Reimbursement Request
3/14/2022

	SUMMARY OF CONTRACTED COSTS		
McShane Contracted Amount:	**$ 184,770.00**		

HARD COSTS BID BREAKDOWN		**Awarded**	**Subcontractor**	
Add Furnish Install two raised asphalt Crosswalks at Chesley Including Demo, Haul Off, Traffic Control and Build Back, Compacted Rock, Ashalt:		$ 125,500.00	O'Grady Paving, Inc. - Low Bidder	(Note 1)
Add and Furnish and Install Pavement Striping and Signage:		$ 16,550.00	Centerline Striping Company, Inc. - Low Bidder	(Note 2)
Add And Furnish and Install Sidewalks, Curb and Gutter, Truncated Domes:		$ 24,900.00	Starch Concrete	
General Contractor Insurance:		$ 2,003.00	McShane	
General Contractor Fee:		$ 5,009.00	McShane	
Additional Costs Incurred During Construction - CAR45:		$ 10,808.00		
Additional Costs Incurred During Construction - SCOR191 - Additional Sign and Marking Work Per County:		$ 2,688.73		
Additional Costs Incurred During Construction - SCOR192 - Additional Construction Survey:		$ 2,805.00		
CTS / Cornerstone Testing & Inspection - Estimate		$ 20,000.00		
Total Hard Costs:		**$ 210,263.73**		
SOFT COSTS:				
Kier & Wright Design/Survey/Asbuilts:	$ 19,500.00			
Post Construction Additional Detailed Suvey Scan Requested by County	$ 6,750.00			
Permit	$ 2,000.00			
Total Soft Costs: Under 14% limit ($210,263.73 * 14% = $29,436.92)	**$ 28,250.00**			
Project Administration @ 14%	**$ 29,436.92**			
Total Hard and Soft Costs For Reimbursement:	**$ 267,950.65**			

Note 1: Alternate Bids Obtained Ramps - Demo/Build Back	
Granite Construction Company	$ 159,000.00
Teichert	$ 131,340.00

Note 2: Alternate Bid Obtained - Striping/Signs	
Garchia Striping Inc.	$ 17,300.00

Nexus Study North Richmond Area of Benefit

Prepared By:
DKS
in association with Urban Economics

Prepared For:
Contra Costa County
Public Works Department

May 2017

Table 6: Selected North Richmond AOB Project List

Roadway/ Project	Location	Recommended Project	Project Number	Basis for Recommendation	Estimated Total Cost
Pittsburg Avenue	Intersection with Richmond Parkway	Intersection Improvements	NR1	Contra Costa County General Plan LOS Standards	$1,183,000
Market Avenue Complete Streets Project	Between Fred Jackson Way and the AOB Boundary (east of railroad tracks)	Pedestrian Improvements	NR3	CCTA CTPL	$6,544,000
	Between Fred Jackson Way and 7th Street	Traffic Calming Including Truck Traffic	NR10	Community Input	
Fred Jackson Way Complete Streets Project	Between Chesley Avenue and Parr Boulevard	Pedestrian and Bicycle Improvements	NR4/NR7	CCTA CTPL	$5,345,000
	Intersection with Chesley Avenue	Traffic Calming Including Truck Traffic	NR9	Previous AOB List	
Parr Boulevard Complete Streets Project	Between Richmond Parkway and AT&SF railroad tracks	Safety, Bicycle and Pedestrian Improvements	NR5	Previous AOB List	$5,527,000
Brookside Drive Complete Streets Project	Between Central Street and AT&SF railroad tracks	Safety, Bicycle and Pedestrian Improvements	NR6	Previous AOB List	$4,892,000
Truck Bypass	Between Market Avenue and Parr Boulevard	Truck Route	NR8	Community Input	$28,453,000
Secondary Access to Verde Elementary School	To be determined	Circulation and Safety Improvements	NR11	Community Input	$2,597,000
Central Street	Between Brookside Drive and Pittsburg Avenue	Safety, Bicycle and Pedestrian Improvements	NR12	Industrial Growth	$1,013,000
Pittsburg Avenue	Between Richmond Parkway and Fred Jackson Way	Safety, Bicycle and Pedestrian Improvements	NR13	Industrial Growth	$2,208,000
Goodrick Avenue	Between Parr Boulevard and AOB Boundary (550' S of Richmond Parkway)	Safety, Bicycle and Pedestrian Improvements	NR14	Industrial Growth	$1,695,000
Chesley Avenue	Between Fred Jackson Way and AOB Boundary	Traffic Calming	NR15	Industrial Growth	$143,000

Source: DKS Associates, 2017

Contra Costa County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Notice of Completion for the 2021 Countywide Curb Ramp Project

RECOMMENDATION(S):
ADOPT Resolution No. 2022/149 accepting as complete the contracted work performed by Sposeto Engineering, Inc, for the 2021 Countywide Curb Ramp Project, as recommended by the Public Works Director, Countywide. County Project No. 0662-6U4000 (All Districts)

FISCAL IMPACT:
The Project was funded by 100% Local Road Funds.

BACKGROUND:
The Public Works Director reports that said work has been inspected and complies with the approved plans, special provisions and standard specifications and recommends its acceptance as complete as of March 1, 2022.

CONSEQUENCE OF NEGATIVE ACTION:
The contractor will not be paid and acceptance notification will not be recorded.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Adelina Huerta 925-313-2305

cc:

AGENDA ATTACHMENTS
Resolution No. 2022/149
MINUTES ATTACHMENTS
Signed: Resolution No 2022/149

Recorded at the request of: **Clerk of the Board**
Return To: **Design/Construction**

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA
and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	**John Gioia, District I SupervisorCandace Andersen, District II SupervisorDiane Burgis, District III SupervisorKaren Mitchoff, District IV SupervisorFederal D. Glover, District V Supervisor**
NO:	
ABSENT:	
ABSTAIN:	
RECUSE:	

Resolution No. 2022/149

The Board of Supervisors RESOLVES that:

Owner (sole): Contra Costa County, 255 Glacier Drive, Martinez, CA 94553

Nature of Stated Owner: fee and/or easement

Project No.: 0662-6U4000

Project Name: 2021 Countywide Curb Ramp Project

Date of Work Completion: March 1, 2022

Description: Contra Costa County on May 11, 2021 contracted with Sposeto Engineering, Inc. for the work generally consisting of removing existing curb and sidewalk and construction of new curb, gutter, and sidewalk to construct over 200 ADA compliant curb ramps at various locations within Countywide areas, all in accordance with the plans, drawings, special provisions and/or specifications prepared by or for the Public Works Director and in accordance with the accepted bid proposal. The project was located countywide, with the Philadelphia Indemnity Insurance Company, as surety, for work to be performed on the grounds of the County; and The Public Works Director reports that said work has been inspected and complies with the approved plans, special provisions and standard specifications and recommends its acceptance as complete as of March 1, 2022.

Identification of real property:

Alamo area:
Stone Valley Road @ Doris Place
Stone Valley Road @ Ranger Court
Doris Place @ Eaton Court
Livorna Road @ Livorna Heights Road
Livorna Road @ Miranda Avenue
Livorna Road @ Falcon View Court
Livorna Road @ Alamo Country Circle
Livorna Road @ Davey Crockett Court

Miranda Avenue @ Megan Court
Miranda Avenue @ Easy Street (north)
Miranda Avenue @ Miranda Place
Bolla Avenue @ Saint Paul Drive
Bolla Avenue @ Lakeview Place
Roundhill Road @ Heritage Oaks
Alamo Country Circle @ Elliot Drive
Alamo Country Circle @ Neely Court
Alamo Country Circle @ Young Court
Alamo Country Circle @ Evelyn Court
Stone Valley Road @ Angela Avenue
Stone Valley Road @ Alamo Glen Drive
Stone Valley Road @ Stone Creek Place
Monte Serano Drive @ Mountai Canyon Place
Monte Serano Drive @ Monte Serano Place
Monte Serano Drive @ Canyon Vista Place
Saint Paul Drive @ Britain Court
Saint Paul Drive @ Buckthorn Place

Castle Hill area:
Tice Valley Boulevard @ Coventry Court
Tice Valley Boulevard @ Tice Hollow Court
Coventry Court @ Candlewood Place

Clyde area:
Norman Avenue @ Kilburn Street
Norman Avenue @ Middlesex Street
Norman Avenue @ Essex Street
Norman Avenue @ Sussex Street
Park Avenue @ Kilburn Street
Wellington Avenue @ Kilburn Street
Wellington Avenue @ Middlesex Street
Wellington Avenue @ Essex Street
Wellington Avenue @ Sussex Street
Wellington Avenue @ Trafalgar Circle
Wellington Avenue @ Wellington Court
Wellington Avenue @ Medburn Street
Park Street @ Highland Court
Park Street @ Sussex Street
Park Place Court @ Park Street
Port Chicago Highway @ Medburn Street

North Concord Area:
Ayers Road @ Laurel Drive

North Richmond Area:
Malcom Drive @ Martin Drive (south)
Malcom Drive @ Maya Way
Malcom Drive @ Marcus Avenue
Malcolm Drive @ Malcom Drive
Martin Drive @ Marcus Drive
Market Avenue @ 1st Street
Market Avenue @ 2nd Street
Market Avenue @ Truman Street

Market Avenue @ 4th Street
Market Avenue @ 5th Street
Market Avenue @ 6th Street
Chesley Avenue @ 1st Street
Chesley Avenue @ 2nd Street
Chesley Avenue @ Truman Street
Chesley Avenue @ 4th Street
Chesley Avenue @ 5th Street
Chesley Avenue @ Giaramita Street
Chesley Avenue @ 6th Street
Chesley Avenue @ 7th Street
Chesley Avenue @ Ruby Avenue
Silver Avenue @ 1st Street
Silver Avenue @ Truman Street
Silver Avenue @ 4th Street
Silver Avenue @ 5th Street
Silver Avenue @ Giaramita Street
Silver Avenue @ 6th Street
Grove Avenue @ 2nd Street
Grove Avenue @ Truman Street
Grove Avenue @ 4th Street
Grove Avenue @ 5th Street
Grove Avenue @ Giaramita Street
Grove Avenue @ 6th Street
Verde Avenue @ Truman Street
Verde Avenue @ 4th Street
Verde Avenue @ 5th Street
Verde Avenue @ 6th Street
Verde Avenue @ 7th Street
W. Ruby Street @ 1st Street
W. Ruby @ 2nd Street
Battery Street @ Duboce Avenue
Battery Street @ Sanford Avenue
Battery Street @ Willard Avenue

Fees: none
Legal References: none
Comments:

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Adelina Huerta 925-313-2305

cc:

C.5

Recorded at the request of: Clerk of the Board
Return To: Design/Construction

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA
and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	**John Gioia, District I SupervisorCandace Andersen, District II SupervisorDiane Burgis, District III SupervisorKaren Mitchoff, District IV SupervisorFederal D. Glover, District V Supervisor**
NO:	
ABSENT:	
ABSTAIN:	
RECUSE:	

Resolution No. 2022/149

The Board of Supervisors RESOLVES that:

Owner (sole): Contra Costa County, 255 Glacier Drive, Martinez, CA 94553

Nature of Stated Owner: fee and/or easement

Project No.: 0662-6U4000

Project Name: 2021 Countywide Curb Ramp Project

Date of Work Completion: March 1, 2022

Description: Contra Costa County on May 11, 2021 contracted with Sposeto Engineering, Inc. for the work generally consisting of removing existing curb and sidewalk and construction of new curb, gutter, and sidewalk to construct over 200 ADA compliant curb ramps at various locations within Countywide areas, all in accordance with the plans, drawings, special provisions and/or specifications prepared by or for the Public Works Director and in accordance with the accepted bid proposal. The project was located countywide, with the Philadelphia Indemnity Insurance Company, as surety, for work to be performed on the grounds of the County; and The Public Works Director reports that said work has been inspected and complies with the approved plans, special provisions and standard specifications and recommends its acceptance as complete as of March 1, 2022.

Identification of real property:

Alamo area:
Stone Valley Road @ Doris Place
Stone Valley Road @ Ranger Court
Doris Place @ Eaton Court
Livorna Road @ Livorna Heights Road
Livorna Road @ Miranda Avenue
Livorna Road @ Falcon View Court
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Stone Valley Road @ Alamo Glen Drive
Stone Valley Road @ Stone Creek Place
Monte Serano Drive @ Mountai Canyon Place
Monte Serano Drive @ Monte Serano Place
Monte Serano Drive @ Canyon Vista Place
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Saint Paul Drive @ Buckthorn Place

Castle Hill area:
Tice Valley Boulevard @ Coventry Court
Tice Valley Boulevard @ Tice Hollow Court
Coventry Court @ Candlewood Place

Clyde area:
Norman Avenue @ Kilburn Street
Norman Avenue @ Middlesex Street
Norman Avenue @ Essex Street
Norman Avenue @ Sussex Street
Park Avenue @ Kilburn Street
Wellington Avenue @ Kilburn Street
Wellington Avenue @ Middlesex Street
Wellington Avenue @ Essex Street
Wellington Avenue @ Sussex Street
Wellington Avenue @ Trafalgar Circle
Wellington Avenue @ Wellington Court
Wellington Avenue @ Medburn Street
Park Street @ Highland Court
Park Street @ Sussex Street
Park Place Court @ Park Street
Port Chicago Highway @ Medburn Street

North Concord Area:
Ayers Road @ Laurel Drive

North Richmond Area:
Malcom Drive @ Martin Drive (south)
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Malcom Drive @ Marcus Avenue
Malcolm Drive @ Malcom Drive
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Market Avenue @ 2nd Street
Market Avenue @ Truman Street

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Grove Avenue @ 5th Street
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Verde Avenue @ 4th Street
Verde Avenue @ 5th Street
Verde Avenue @ 6th Street
Verde Avenue @ 7th Street
W. Ruby Street @ 1st Street
W. Ruby @ 2nd Street
Battery Street @ Duboce Avenue
Battery Street @ Sanford Avenue
Battery Street @ Willard Avenue

Fees: none
Legal References: none
Comments:

Contact: Adelina Huerta 925-313-2305

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M. Boyd

By: Stacey M. Boyd, Deputy

cc:

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Contra Costa County

Subject: Approving the thirteenth extension of the Subdivision Agreement for subdivision SD06-09131, Bay Point area.

RECOMMENDATION(S):
ADOPT Resolution No. 2022/138 approving the thirteenth extension of the Subdivision Agreement for subdivision SD06-09131, for a project being developed by Jasraj Singh & Tomas Baluyut, as recommended by the Public Works Director, Bay Point area. (District V)

FISCAL IMPACT:
No fiscal impact.

BACKGROUND:
The termination date of the Subdivision Agreement needs to be extended. The developer has not completed the required improvements and has requested more time. (Approximately 99% of the work has been completed to date.) By granting an extension, the County will give the developer more time to complete his improvements and keeps the bond current.

CONSEQUENCE OF NEGATIVE ACTION:
The termination date of the Subdivision Agreement will not be extended and the developer will be in default of the agreement, requiring the County to take legal action against the developer and surety to get the improvements installed, or revert the development to acreage.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Ronald Lai, Engineering Services, Ruben Hernandez - DCD, Jasraj Singh & Tomas Baluyut - Developer, Developers Surety and Indemnity

AGENDA ATTACHMENTS

Resolution No. 2022/138

Subdivision Agreement Extension

MINUTES ATTACHMENTS

Signed: Resolution No. 2022/138

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/138

IN THE MATTER OF approving the thirteenth extension of the Subdivision Agreement for subdivision SD06-09131, for a project being developed by Jasraj Singh & Tomas Baluyut, as recommended by the Public Works Director, Bay Point area. (District V)

WHEREAS the Public Works Director, having recommended that he be authorized to execute the thirteenth agreement extension which extends the subdivision agreement between Jasraj Singh & Tomas Baluyut and the County for construction of certain improvements in subdivision SD06-09131, Bay Point area, through May 15, 2023.

APPROXIMATE PERCENTAGE OF WORK COMPLETE: 99%

ANTICIPATED DATE OF COMPLETION: November 2022

BOND NO.: 761783S Date: April 9, 2007

REASON FOR EXTENSION: Due to construction finances, developer needs more time to complete work.

NOW, THEREFORE, BE IT RESOLVED that the recommendation of the Public Works Director is APPROVED.

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Ronald Lai, Engineering Services, Ruben Hernandez - DCD, Jasraj Singh & Tomas Baluyut - Developer, Developers Surety and Indemnity

CONTRA COSTA COUNTY

SUBDIVISION AGREEMENT EXTENSION

Development Number: SD06-09131

Developer: Jasraj Singh & Tomas Baluyut

Original Agreement Date: May 15, 2007

Extension New Termination Date: May 15, 2023

Improvement Security

SURETY: **Developers Surety and Indemnity**

BOND No. 761783S	**Date: April 9, 2007**
Security Type	**Security Amount**
Cash:	**$ 1,000.00 (1% cash, $1,000 Min.)**
SURETY BOND:	**$ 59,900.00 (Performance)**
	$ 30,450.00 (Labor& Material)

The Developer and the Surety desire this Agreement to be extended through the above date: and Contra Costa County and said Surety hereby agree thereto and acknowledge same.

Dated: ______________

FOR CONTRA COSTA COUNTY
Brian M. Balbas, Public Works Director

By: ______________

RECOMMENDED FOR APPROVAL:

By: ______________
(Engineering Services Division)

(NOTE: Developer's, Surety's and Financial Institution's Signatures must be Notarized.)

FORM APPROVED Victor J. Westman, County Counsel

After Approval Return to Clerk of the Board

Dated: March 22nd, 2022

Developer's Signature(s)

JASRAJ SINGH
Printed

Developer's Signature(s)

TOMAS BALUYUT
Printed

2744 ROOSEVELT LANE, ANTIOCH. CA 94509
Address See attached Acknowledgment.

Developers Surety and Indemnity
Surety or Financial Institution

17771 Cowan, Suite C, Irvine, CA 92614
Address

Attorney in Facts Signature

Mike Herranen
Printed

See attached loose notarial certificate.

MMC 3/26/2022

STATE OF Arizona

COUNTY OF Maricopa]

On 03/22/2022 *, before me,* Michele Faucett, Notary Public ,
(here insert name and title of the officer), personally appeared Mike Herranen
,
personally known to me (or proved to me on the basis of satisfactory evidence) to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

WITNESS my hand and official seal.

Signature Michele Faucett *(SEAL)*

MICHELE FAUCETT
NOTARY PUBLIC ARIZONA
MARICOPA COUNTY
MY COMMISSION EXPIRES
APRIL 01, 2022

This area for Official Notarial Seal

OPTIONAL

Though the data below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent reattachment of this form.

CAPACITY CLAIMED BY SIGNER

☐ INDIVIDUAL
☐ CORPORATE OFFICER

TITLE(S)

☐ PARTNER(S) ☐ LIMITED
☐ GENERAL
☐ ATTORNEY-IN-FACT
☐ TRUSTEE(S)
☐ GUARDIAN/CONSERVATOR
☐ OTHER:

SIGNER IS REPRESENTING:
NAME OF PERSON(S) OR ENTITY(IES)

DESCRIPTION OF ATTACHED DOCUMENT

TITLE OF TYPE OF DOCUMENT

NUMBER OF PAGES

DATE OF DOCUMENT

SIGNER(S) OTHER THAN NAMED ABOVE

ALL-PURPOSE ACKNOWLEDGEMENT

POWER OF ATTORNEY FOR
DEVELOPERS SURETY AND INDEMNITY COMPANY
INDEMNITY COMPANY OF CALIFORNIA
PO Box 19725, IRVINE, CA 92623 (949) 263-3300

KNOW ALL BY THESE PRESENTS that except as expressly limited, DEVELOPERS SURETY AND INDEMNITY COMPANY and INDEMNITY COMPANY OF CALIFORNIA, do each hereby make, constitute and appoint:

Thomas C. Buckner, Mike Herranen, jointly or severally

as their true and lawful Attorney(s)-in-Fact, to make, execute, deliver and acknowledge, for and on behalf of said corporations, as sureties, bonds, undertakings and contracts of suretyship giving and granting unto said Attorney(s)-in-Fact full power and authority to do and to perform every act necessary, requisite or proper to be done in connection therewith as each of said corporations could do, but reserving to each of said corporations full power of substitution and revocation, and all of the acts of said Attorney(s)-in-Fact, pursuant to these presents, are hereby ratified and confirmed.

This Power of Attorney is granted and is signed by facsimile under and by authority of the following resolutions adopted by the respective Boards of Directors of DEVELOPERS SURETY AND INDEMNITY COMPANY and INDEMNITY COMPANY OF CALIFORNIA, effective as of January 1st, 2008.

RESOLVED, that a combination of any two of the Chairman of the Board, the President, Executive Vice-President, Senior Vice-President or any Vice President of the corporations be, and that each of them hereby is, authorized to execute this Power of Attorney, qualifying the attorney(s) named in the Power of Attorney to execute, on behalf of the corporations, bonds, undertakings and contracts of suretyship; and that the Secretary or any Assistant Secretary of either of the corporations be, and each of them hereby is, authorized to attest the execution of any such Power of Attorney;

RESOLVED, FURTHER, that the signatures of such officers may be affixed to any such Power of Attorney or to any certificate relating thereto by facsimile, and any such Power of Attorney or certificate bearing such facsimile signatures shall be valid and binding upon the corporations when so affixed and in the future with respect to any bond, undertaking or contract of suretyship to which it is attached.

IN WITNESS WHEREOF, DEVELOPERS SURETY AND INDEMNITY COMPANY and INDEMNITY COMPANY OF CALIFORNIA have severally caused these presents to be signed by their respective officers and attested by their respective Secretary or Assistant Secretary this 4th day of October, 2018.

By: Daniel Young
Daniel Young, Senior Vice-President

By:
Mark Lansdon, Vice-President

DEVELOPERS SURETY AND INDEMNITY COMPANY INCORPORATED 1936 CALIFORNIA

INDEMNITY COMPANY OF CALIFORNIA INCORPORATED OCT. 5 1967

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California
County of Orange

On October 4, 2018 (Date) before me, Lucille Raymond, Notary Public (Here Insert Name and Title of the Officer)

personally appeared Daniel Young and Mark Lansdon (Name(s) of Signer(s))

LUCILLE RAYMOND
Notary Public - California
Orange County
Commission # 2258185
My Comm. Expires Oct 13, 2022

Place Notary Seal Above

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature Lucille Raymond
Lucille Raymond, Notary Public

CERTIFICATE

The undersigned, as Secretary or Assistant Secretary of DEVELOPERS SURETY AND INDEMNITY COMPANY or INDEMNITY COMPANY OF CALIFORNIA, does hereby certify that the foregoing Power of Attorney remains in full force and has not been revoked and, furthermore, that the provisions of the resolutions of the respective Boards of Directors of said corporations set forth in the Power of Attorney are in force as of the date of this Certificate.

This Certificate is executed in the City of Irvine, California, this 22nd day of March, 2022

By: Cassie J. Berrisford
Cassie J. Berrisford, Assistant Secretary

DEVELOPERS SURETY AND INDEMNITY COMPANY INCORPORATED 1936 CALIFORNIA

INDEMNITY COMPANY OF CALIFORNIA INCORPORATED OCT. 5 1967

ATS-1002 (10/18)

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT **CIVIL CODE § 1189**

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)
County of Los Angeles)

On March 26, 2022 before me, Jack M Crawford, Notary Public
Date *Here Insert Name and Title of the Officer*

personally appeared Jasraj Singh
Name(s) of Signer(s)

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

JACK M. CRAWFORD
Notary Public - California
Los Angeles County
Commission # 2353460
My Comm. Expires Mar 31, 2025

Signature *Signature of Notary Public*

Place Notary Seal Above

OPTIONAL

Though this section is optional, completing this information can deter alteration of the document or fraudulent reattachment of this form to an unintended document.

Description of Attached Document
Title or Type of Document: Contra Costa County Subdivision Agreement Extension Document Date: 3/22/2022
Number of Pages: 1 Signer(s) Other Than Named Above: Mike Hennahen

Capacity(ies) Claimed by Signer(s)

Signer's Name: Jasraj Singh	Signer's Name:
☐ Corporate Officer — Title(s):	☐ Corporate Officer — Title(s):
☐ Partner — ☐ Limited ☐ General	☐ Partner — ☐ Limited ☐ General
☑ Individual ☐ Attorney in Fact	☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator	☐ Trustee ☐ Guardian or Conservator
☐ Other:	☐ Other:
Signer Is Representing: Self	Signer Is Representing:

CALIFORNIA CERTIFICATE OF ACKNOWLEDGMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)

County of Contra Costa)

On April 1/2022 before me, Reshmini Dealmeida Notary Public (here insert name and title of the officer)

personally appeared Tomas Baluyut,

who proved to me on the basis of satisfactory evidence to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she~~/~~they~~ executed the same in his/~~her~~/~~their~~ authorized capacity(~~ies~~), and that by his/~~her~~/~~their~~ signature(~~s~~) on the instrument the person(~~s~~), or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

RESHMINI DEALMEIDA
COMM. #2382405
Notary Public - California
Contra Costa County
My Comm. Expires Nov. 10, 2025
NR01

WITNESS my hand and official seal.

Signature R Dealmeida (Seal)

Optional Information

Although the information in this section is not required by law, it could prevent fraudulent removal and reattachment of this acknowledgment to an unauthorized document and may prove useful to persons relying on the attached document.

Description of Attached Document

The preceding Certificate of Acknowledgment is attached to a document titled/for the purpose of Subdivision Agreement Extension

containing 1 pages, and dated 3/22/2022.

The signer(~~s~~) capacity or authority is/~~are~~ as:

- [x] Individual(~~s~~)
- [ ] Attorney-in-Fact
- [ ] Corporate Officer(s) ______ Title(s)
- [ ] Guardian/Conservator
- [ ] Partner - Limited/General
- [ ] Trustee(s)
- [ ] Other: ______

representing: ______ Name(s) of Person(s) or Entity(ies) Signer is Representing

Additional Information

Method of Signer Identification

Proved to me on the basis of satisfactory evidence:
○ form(s) of identification ○ credible witness(es)

Notarial event is detailed in notary journal on:
Page # ______ Entry # ______

Notary contact: ______

Other

- [ ] Additional Signer(s)
- [ ] Signer(s) Thumbprint(s)
- [ ] ______

C.6

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/138

IN THE MATTER OF approving the thirteenth extension of the Subdivision Agreement for subdivision SD06-09131, for a project being developed by Jasraj Singh & Tomas Baluyut, as recommended by the Public Works Director, Bay Point area. (District V)

WHEREAS the Public Works Director, having recommended that he be authorized to execute the thirteenth agreement extension which extends the subdivision agreement between Jasraj Singh & Tomas Baluyut and the County for construction of certain improvements in subdivision SD06-09131, Bay Point area, through May 15, 2023.

APPROXIMATE PERCENTAGE OF WORK COMPLETE: 99%

ANTICIPATED DATE OF COMPLETION: November 2022

BOND NO.: 761783S Date: April 9, 2007

REASON FOR EXTENSION: Due to construction finances, developer needs more time to complete work.

NOW, THEREFORE, BE IT RESOLVED that the recommendation of the Public Works Director is APPROVED.

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M Boyd

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Ronald Lai, Engineering Services, Ruben Hernandez - DCD, Jasraj Singh & Tomas Baluyut - Developer, Developers Surety and Indemnity

C. 7

Contra Costa County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Accepting for recording purposes only an Offer of Dedication for Roadway Purposes for minor subdivision MS19-00007, Walnut Creek area.

RECOMMENDATION(S):

ADOPT Resolution No. 2022/142 accepting for recording purposes only an Offer of Dedication for Roadway Purposes for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

FISCAL IMPACT:

No fiscal impact.

BACKGROUND:

The Offer of Dedication for Roadway Purposes is required per Condition of Approval No. 25.

CONSEQUENCE OF NEGATIVE ACTION:

The Offer of Dedication for Roadway Purposes will not be recorded.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Dante Morabe - Design & Construction, Margaret Mitchell- DCD, Chris Lau - Maintenance, Renee Hutchins - Records, Karen Piona- Records, Campos Development, LLC

AGENDA <u>ATTACHMENTS</u>

Resolution No. 2022/142

Offer of Dedication - Road Purposes

<u>MINUTES ATTACHMENTS</u>

<u>Signed: Resolution No. 2022/142</u>

Recorded at the request of: **Clerk of the Board**
Return To: **Public Works Dept- Simone Saleh**

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA
and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	**John Gioia, District I SupervisorCandace Andersen, District II SupervisorDiane Burgis, District III SupervisorKaren Mitchoff, District IV SupervisorFederal D. Glover, District V Supervisor**
NO:	
ABSENT:	
ABSTAIN:	
RECUSE:	

Resolution No. 2022/142

IN THE MATTER OF accepting for recording purposes only an Offer of Dedication for Roadway Purposes for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

NOW, THEREFORE, BE IT RESOLVED that the following instrument is hereby ACCEPTED FOR RECORDING ONLY :
INSTRUMENT: Offer of Dedication for Roadway Purposes
REFERENCE: APN 183-172-001
GRANTOR: Campos Development, LLC
AREA: Walnut Creek
DISTRICT: IV

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Randolf Sanders (925) 313-2111

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Dante Morabe - Design & Construction, Margaret Mitchell- DCD, Chris Lau - Maintenance, Renee Hutchins - Records, Karen Piona- Records, Campos Development, LLC

Recorded at the request of:
Contra Costa County
Board of Supervisors
Return to:
Public Works Department
Engineering Services Division
Records Section

Area: Walnut Creek
Road: Norris Road
Co. Road No.: 4245CG
Development No.: MS19-0007
APN: 183-172-001

OFFER OF DEDICATION - ROAD PURPOSES

James Campos, Managing member Campos Development, LLC, the undersigned, being the present title owner of record of the herein described parcel of land, do hereby make an irrevocable offer of dedication to **Contra Costa County**, a political subdivision of the State of California and its successors or assigns, for street, highway landscaping and other public purposes, including maintenance thereof, the fee title to real property situated in the County of Contra Costa, State of California, as described in Exhibit "A" (written description) and as shown on Exhibit "B" (plat map) attached hereto.

It is understood and agreed that **Contra Costa County** and its successors or assigns shall incur no liability with respect to such offer of dedication, and shall not assume any responsibility for the offered parcel of land or any improvements thereon or therein, until such offer has been accepted by appropriate action of the Board of Supervisors, or of the local governing bodies of its successors or assigns.

The provisions hereof shall inure to the benefit of **Contra Costa County** and its successors or assigns and will be binding upon the title owner of record and that owner's heirs, successors or assigns.

For more information, see attached resolution that was approved by the BOS for this offer of dedication.

The undersigned executed this instrument on 3/18/22.
(Date)

Campos Development, LLC
(Name of owner as shown in title report)

(Signature) [signature], Managing member
(Print Name & Title)

(Signature) James Campos, Managing member
(Print Name & Title)

Attachments: Notary
Exhibit A & B
Resolution

See Attached for Notarization

JD:lad:rm
\\pw-data\grpdata\engsvc\Land Dev\MS\MS 19-0007\OF-6 - Road Purposes.doc
Rev. May 1, 2003
Approved by County Counsel – 4/29/03

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT **CIVIL CODE § 1189**

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)
County of Contra Costa)

On 4/12/2022 before me, Megan Dennis, Notary Public,
Date — *Here Insert Name and Title of the Officer*

personally appeared James Campos
Name(s) of Signer(s)

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

MEGAN DENNIS
Notary Public - California
Contra Costa County
Commission # 2370288
My Comm. Expires Aug 10, 2025

Signature ____________
Signature of Notary Public

Place Notary Seal Above

OPTIONAL

Though this section is optional, completing this information can deter alteration of the document or fraudulent reattachment of this form to an unintended document.

Description of Attached Document

Title or Type of Document: ______ Document Date: ______

Number of Pages: ______ Signer(s) Other Than Named Above: ______

Capacity(ies) Claimed by Signer(s)

Signer's Name: ______
☐ Corporate Officer — Title(s): ______
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______
Signer Is Representing: ______

Signer's Name: ______
☐ Corporate Officer — Title(s): ______
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______
Signer Is Representing: ______

EXHIBIT'A'
LEGAL DESCRIPTION
ROADWAY DEDICATION

ALL THAT CERTAIN REAL PROPERTY SITUATED IN THE UNINCORPORATED AREA OF COUNTY OF CONTRA COSTA, STATE OF CALIFORNIA, MORE PARTICULARLY DESCRIBED AS FOLLOWS:

(THE BEARINGS FOR THE PURPOSE OF THIS DESCRIPTION ARE BASED UPON THE MAP OF NORRIS ADDITION TO WALNUT HEIGHTS FILED IN BOOK 7 OF MAPS AT PAGE 174, IN THE OFFICE OF THE COUNTY RECORDER OF CONTRA COSTA COUNTY, STATE OF CALIFORNIA)

BEING A PORTION OF THAT PARCEL OF LAND DESCRIBED IN THE DEED TO CAMPOS DEVELOPMENT RECORDED ON MAY 24, 2019 UNDER RECORDERS SERIES NUMBER 2019-0076767 IN THE OFFICE OF THE COUNTY RECORDER OF CONTRA COSTA COUNTY, STATE OF CALIFORNIA, MORE PARTICULARLY DESCRIBED AS FOLLOWS:

BEGINNING AT THE MOST NORTHERLY CORNER OF SAID PARCEL (2019-0076767) THENCE ALONG THE NORTHWESTERLY LINE THEREOF SOUTH 31°06'00" WEST, 25.00 FEET;

THENCE LEAVING SAID NORTHWESTERLY LINE SOUTH 58°54'00" EAST, 73.68 FEET;

THENCE, ALONG A NON-TANGENT CURVE TO THE RIGHT WHOSE RADIUS POINT BEARS NORTH 81°11'56" WEST 31.00 FEET, THROUGH A CENTRAL ANGLE OF 22°25'16", AND AN ARC LENGTH OF 12.13 FEET;

THENCE SOUTH 31°13'20" WEST, 13.00 FEET;

THENCE SOUTH 58°46'40" EAST, 20.00 FEET;

THENCE NORTH 31°13'20" EAST, 13.00 FEET;

THENCE, ALONG A TANGENT CURVE TO THE RIGHT WITH A RADIUS OF 31.00 FEET, THROUGH A CENTRAL ANGLE OF 22°31'35", AND AN ARC LENGTH OF 12.19 FEET;

THENCE SOUTH 58°54'00" EAST, 12.61 FEET TO A POINT ON THE SOUTHEASTERLY LINE OF SAID PARCEL (2019-0076767);

THENCE ALONG SAID SOUTHEASTERLY LINE NORTH 31°06'00" EAST, 25.00 FEET TO THE NORTHERLY LINE OF SAID PARCEL, SAID LINE ALSO BEING THE CENTERLINE OF NORRIS ROAD AS SHOWN ON SAID MAP (7 M 174) ;

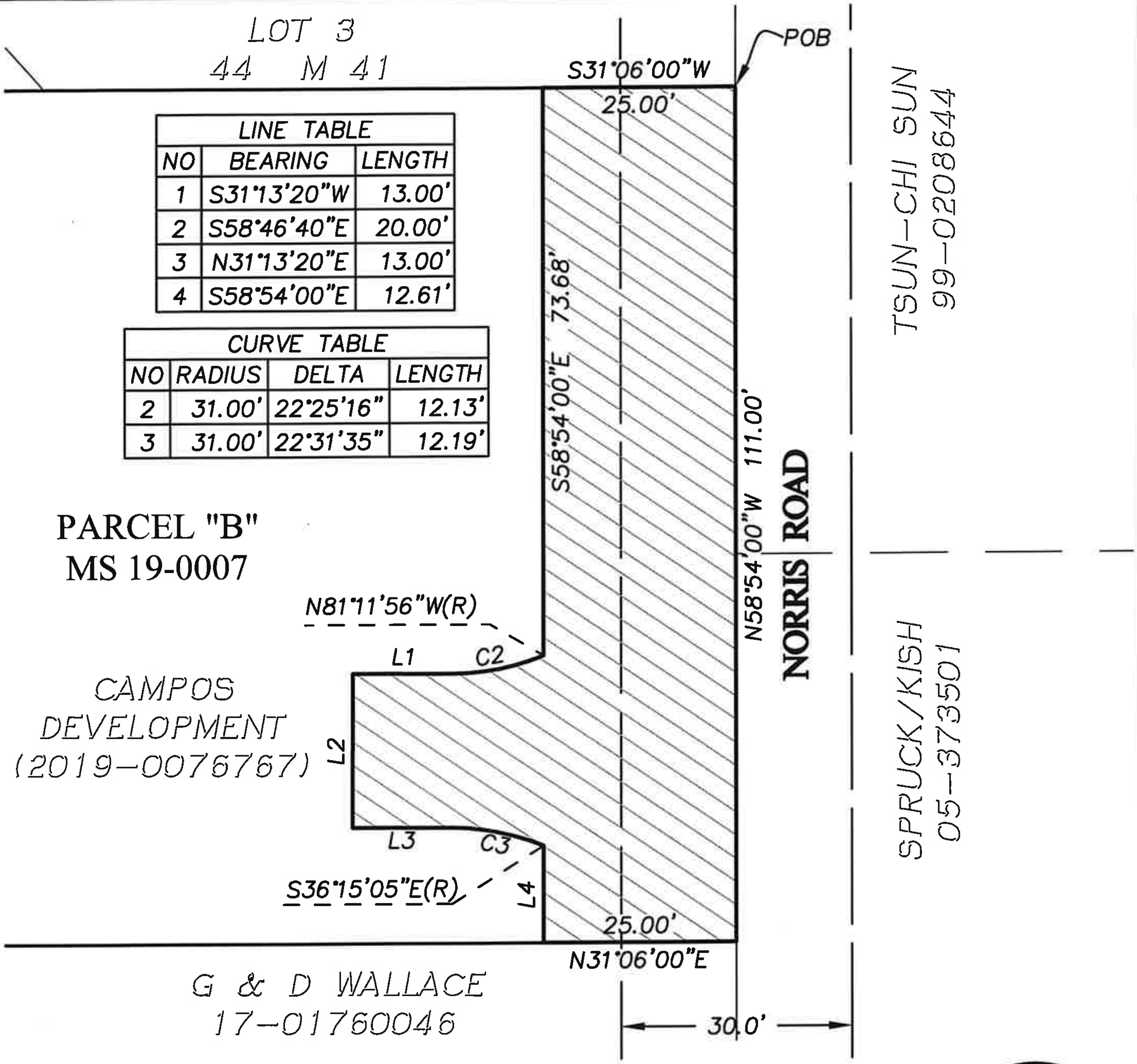
THENCE ALONG SAID NORTHERLY LINE NORTH 58°54'00" WEST, 111.00 FEET TO THE **POINT OF BEGINNING**.

CONTAINING 3,290 SQUARE FEET OF LAND, MORE OR LESS.

THIS REAL PROPERTY DESCRIPTION HAS BEEN PREPARED BY ME, OR UNDER MY DIRECTION, IN CONFORMANCE WITH THE PROFESSIONAL LAND SURVEYORS ACT

BOB J. LEZCANO-LS8514

LICENSED LAND SURVEYOR
BOB J.
LEZCANO
3/4/22
PLS 8514
STATE OF CALIFORNIA



LINE TABLE		
NO	BEARING	LENGTH
1	S31°13'20"W	13.00'
2	S58°46'40"E	20.00'
3	N31°13'20"E	13.00'
4	S58°54'00"E	12.61'

CURVE TABLE			
NO	RADIUS	DELTA	LENGTH
2	31.00'	22°25'16"	12.13'
3	31.00'	22°31'35"	12.19'

LEGEND

POB POINT OF BEGINNING

(R) RADIAL

DEDICATION AREA =3,290 SF±

BASIS OF BEARINGS

BASIS OF BEARINGS WAS TAKEN AS NORTH 58°54'00" WEST ON THE CENTER LINE OF NORRIS ROAD AS SHOWN ON "MAP NO. 1 "NORRIS ADDITION TO WALNUT HEIGHTS", FILED IN BOOK 7 OF MAPS AT PAGE 174,

LICENSED LAND SURVEYOR BOB J. LEZCANO L.S. 8514 STATE OF CALIFORNIA

3-21-22

APEX CIVIL ENGINEERING & LAND SURVEYING

817 Arnold Drive Ste. 50
Martinez, CA 94553
Ph: (925) 476-8499

EXHIBIT 'B'

PLAT TO ACCOMPANY LEGAL DESCRIPTION

DRAWN BY: BJL	SHEET 1 OF 1
PROJECT NO: 19038	
SCALE: 1"-20'	DATE: 12-16-2021

c.7

Recorded at the request of: Clerk of the Board
Return To: Public Works Dept- Simone Saleh

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA
and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	**John Gioia, District I SupervisorCandace Andersen, District II SupervisorDiane Burgis, District III SupervisorKaren Mitchoff, District IV SupervisorFederal D. Glover, District V Supervisor**
NO:	
ABSENT:	
ABSTAIN:	
RECUSE:	

Resolution No. 2022/142

IN THE MATTER OF accepting for recording purposes only an Offer of Dedication for Roadway Purposes for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

NOW, THEREFORE, BE IT RESOLVED that the following instrument is hereby ACCEPTED FOR RECORDING ONLY :
INSTRUMENT: Offer of Dedication for Roadway Purposes
REFERENCE: APN 183-172-001
GRANTOR: Campos Development, LLC
AREA: Walnut Creek
DISTRICT: IV

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M Boyd

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Dante Morabe - Design & Construction, Margaret Mitchell- DCD, Chris Lau - Maintenance, Renee Hutchins - Records, Karen Piona- Records, Campos Development, LLC

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Contra Costa County

Subject: Approve the Parcel Map for minor subdivision MS19-00007, Walnut Creek area.

RECOMMENDATION(S):
ADOPT Resolution No. 2022/143 approving the Parcel Map and Subdivision Agreement for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

FISCAL IMPACT:
No fiscal impact.

BACKGROUND:
The Public Works Department has reviewed the conditions of approval for minor subdivision MS19-00007 and has determined that all conditions of approval for Parcel Map approval have been satisfied.

CONSEQUENCE OF NEGATIVE ACTION:
The Parcel Map and the Subdivision Agreement will not be approved and recorded.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Renee Hutchins - Records, Karen Piona- Records, Dante Morabe - Design & Construction, Chris Hallford -Mapping , Michael Mann- Finance, Chris Lau - Maintenance, Margaret Mitchell- DCD, Campos Development, LLC, Hudson Insurance Company

AGENDA ATTACHMENTS
Resolution No. 2022/143
Parcel Map
Subdivision Agreement & Improvement Security Bond
Tax Letter
MINUTES ATTACHMENTS
Signed: Resolution No. 2022/143

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/143

IN THE MATTER OF approving the Parcel Map and Subdivision Agreement for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

WHERE AS, the following documents were presented for board approval this date:

I. Map

The Parcel Map of minor subdivision MS19-00007, property located in the Walnut Creek area, Supervisorial District IV, said map having been certified by the proper officials.

II. Subdivision Agreement

A subdivision agreement with Campos Development, LLC, principal, whereby said principal agrees to complete all improvements as required in said subdivision agreement within 2 year(s) from the date of said agreement. Accompanying said subdivision agreement is security guaranteeing completion of said improvements as follows:

A. Cash Bond

Performance amount: $1,000.00

Auditor’s Deposit Permit No. DP844778 Date: March 3, 2022

Submitted by: Campos Development, LLC

B. Surety Bond

Bond Company: Hudson Insurance Company

Bond Number: 60008856 Date: March 18, 2022

Performance Amount: $80,000.00

Labor & Materials Amount: $40,500.00

Principal: Campos Development, LLC

III. Tax Letter

Letter from the County Tax Collector stating that there are no unpaid County taxes heretofore levied on the property included in said map and that the 2021-2022 tax lien has been paid in full and the 2022-2023 tax lien, which became a lien on the first day of January 2022, is estimated to be $20,460.00, with security guaranteeing payment of said tax lien as follows:

- Tax Surety

Auditor's Deposit Permit Number: DP845781 Date: March 21, 2022

Amount: $20,460.00

Submitted by/Principal: Campos Development, LLC

NOW, THEREFORE, BE IT RESOLVED:

1. That said subdivision, together with the provisions for its design and improvement, is DETERMINED to be consistent with the County's general and specific plans.

2. That said map is APPROVED and this Board does hereby *accept subject to installation and acceptance of improvements* on behalf of the public any of the streets, paths, or easements shown thereon as dedicated to public use.

3. That said subdivision agreement is also APPROVED.

Contact: Randolf Sanders (925) 313-2111

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Renee Hutchins - Records, Karen Piona- Records, Dante Morabe - Design & Construction, Chris Hallford -Mapping , Michael Mann- Finance, Chris Lau - Maintenance, Margaret Mitchell- DCD, Campos Development, LLC, Hudson Insurance Company

OWNER'S STATEMENT

THE UNDERSIGNED, BEING THE ONLY PARTY HAVING A RECORD TITLE INTEREST IN THE LANDS DELINEATED AND EMBRACED WITHIN THE HEAVY BLACK LINES UPON THIS PARCEL MAP, DOES HEREBY CONSENT TO THE MAKING AND RECORDATION OF THE SAME, AND DOES HEREBY DEDICATE IN FEE TO THE PUBLIC FOR PUBLIC USE AND TO THE COUNTY OF CONTRA COSTA, FOR ROADWAY PURPOSES THOSE PORTIONS OF SAID LANDS DESIGNATED ON SAID MAP AS: "NORRIS ROAD DEDICATION". SAID DEDICATION IS BY SEPARATE INSTRUMENT RECORDED CONCURRENTLY WITH THE FILING OF THIS MAP PER RECORDERS SERIES NO. ____________

THE REAL PROPERTY DESCRIBED BELOW IS OFFERED FOR DEDICATION AS AN EASEMENT FOR PUBLIC PURPOSES: THE AREAS DESIGNATED AS "PUBLIC UTILITY EASEMENTS" OR "PUE" ARE FOR PUBLIC UTILITY PURPOSES INCLUDING POLES, WIRES, CONDUITS, STORM DRAINS, FLOOD AND SURFACE WATER DRAINAGE, GAS LINES, ELECTRIC, TELEPHONE AND CABLE TELEVISION UTILITIES, INCLUDING THE RIGHTS OF INGRESS, EGRESS, CONSTRUCTION, RECONSTRUCTION. ACCESS FOR MAINTENANCE OF WORKS, IMPROVEMENTS, AND STRUCTURES, AND THE CLEARING OF OBSTRUCTIONS AND VEGETATION.

THE AREA DESIGNATED AS "PSDE" (PRIVATE STORM DRAIN EASEMENT) ARE FOR PRIVATE STORM DRAIN PURPOSES TO INCLUDE THE RIGHTS TO CONSTRUCT AND MAINTAIN PRIVATE STORM DRAIN STRUCTURES AND PIPES FOR THE BENEFIT OF PARCEL 'B' OF THIS SUBDIVISION

THIS MAP SHOWS ALL EASEMENTS ON THE PREMISES OR OF RECORD.

CAMPOS DEVELOPMENT, LLC, A CALIFORNIA LIMITED LIABILITY COMPANY

BY: ____________________
JAMES CAMPOS, MANAGER

OWNER'S ACKNOWLEDGEMENT

A NOTARY PUBLIC OR OTHER OFFICER COMPLETING THIS CERTIFICATE VERIFIES ONLY THE IDENTITY OF THE INDIVIDUAL WHO SIGNED THE DOCUMENT TO WHICH THIS CERTIFICATE IS ATTACHED, AND NOT THE TRUTHFULNESS, ACCURACY, OR VALIDITY OF THAT DOCUMENT.

STATE OF CALIFORNIA)
COUNTY OF CONTRA COSTA) SS

ON ____________, 20__, BEFORE ME, ____________________,
A NOTARY PUBLIC, PERSONALLY APPEARED ____________________
WHO PROVED TO ME ON THE BASIS OF SATISFACTORY EVIDENCE TO BE THE PERSON(S) WHOSE NAME(S) IS/ARE SUBSCRIBED TO THE WITHIN INSTRUMENT AND ACKNOWLEDGED TO ME THAT HE/SHE/THEY EXECUTED THE SAME IN HIS/HER/THEIR AUTHORIZED CAPACITY(IES), AND THAT BY HIS/HER/THEIR SIGNATURE(S) ON THE INSTRUMENT THE PERSON(S), OR THE ENTITY UPON BEHALF OF WHICH THE PERSON(S) ACTED, EXECUTED THE INSTRUMENT.

I CERTIFY UNDER PENALTY OF PERJURY UNDER THE LAWS OF THE STATE OF CALIFORNIA THAT THE FOREGOING IS TRUE AND CORRECT.

WITNESS MY HAND

SIGNATURE NOTARY: ____________________

NAME (PRINTED OR TYPED): ____________________

MY COMMISSION EXPIRES: ____________________

COUNTY OF NOTARY: ____________________

PRINCIPAL PLACE OF BUSINESS: ____________________

PARCEL MAP

SUBDIVISION MS 19-0007

BEING A SUBDIVISION OF THAT PARCEL OF LAND DESCRIBED IN THE DOCUMENT 2019-076767, AND BEING A PORTION OF LOT 4 AS SHOWN ON THE MAP OF THE NORRIS ADDITION TO WALNUT HEIGHTS (7 M 174)

CONTRA COSTA COUNTY, CALIFORNIA

APEX
CIVIL ENGINEERING & LAND SURVEYING
817 Arnold Drive, Ste. 50
Martinez, CA 94553
Ph: (925) 476-8499
www.apexce.net

JANUARY, 2022

BENEFICIARY'S STATEMENT

THE UNDERSIGNED, AS BENEFICIARY UNDER THE DEED OF TRUST RECORDED MAY 24, 2019 IN OFFICIAL RECORDS SERIES NO. 2019-076768 CONTRA COSTA COUNTY RECORDS, HEREBY CONSENTS TO THE PREPARATION AND RECORDATION OF THIS FINAL MAP AND JOINS IN ALL OFFERS OF DEDICATION THEREIN.

FJM PRIVATE MORTGAGE FUND, LLC, A CALIFORNIA LIMITED LIABILITY COMPANY

BY: ____________________

DATE: ____________________

PRINT NAME: ____________________

TITLE: ____________________

BENEFICIARY'S ACKNOWLEDGEMENT

A NOTARY PUBLIC OR OTHER OFFICER COMPLETING THIS CERTIFICATE VERIFIES ONLY THE IDENTITY OF THE INDIVIDUAL WHO SIGNED THE DOCUMENT TO WHICH THIS CERTIFICATE IS ATTACHED, AND NOT THE TRUTHFULNESS, ACCURACY, OR VALIDITY OF THAT DOCUMENT.

STATE OF CALIFORNIA)
COUNTY OF CONTRA COSTA) SS

ON ____________, 20__, BEFORE ME, ____________________,
A NOTARY PUBLIC, PERSONALLY APPEARED ____________________
WHO PROVED TO ME ON THE BASIS OF SATISFACTORY EVIDENCE TO BE THE PERSON(S) WHOSE NAME(S) IS/ARE SUBSCRIBED TO THE WITHIN INSTRUMENT AND ACKNOWLEDGED TO ME THAT HE/SHE/THEY EXECUTED THE SAME IN HIS/HER/THEIR AUTHORIZED CAPACITY(IES), AND THAT BY HIS/HER/THEIR SIGNATURE(S) ON THE INSTRUMENT THE PERSON(S), OR THE ENTITY UPON BEHALF OF WHICH THE PERSON(S) ACTED, EXECUTED THE INSTRUMENT.

I CERTIFY UNDER PENALTY OF PERJURY UNDER THE LAWS OF THE STATE OF CALIFORNIA THAT THE FOREGOING IS TRUE AND CORRECT.

WITNESS MY HAND

SIGNATURE NOTARY: ____________________

NAME (PRINTED OR TYPED): ____________________

MY COMMISSION EXPIRES: ____________________

COUNTY OF NOTARY: ____________________

PRINCIPAL PLACE OF BUSINESS: ____________________

BENEFICIARY'S STATEMENT

THE UNDERSIGNED, AS BENEFICIARY UNDER THE DEED OF TRUST RECORDED MAY 24, 2019 IN OFFICIAL RECORDS SERIES NO. 2019- 076769 CONTRA COSTA COUNTY RECORDS, HEREBY CONSENTS TO THE PREPARATION AND RECORDATION OF THIS FINAL MAP AND JOINS IN ALL OFFERS OF DEDICATION THEREIN.

GRANT M. BARNES, TRUSTEE UNDER THE GRANT M. BARNES TRUST

BY: ____________________

DATE: ____________________

PRINT NAME: ____________________

TITLE: ____________________

BENEFICIARY'S ACKNOWLEDGEMENT

A NOTARY PUBLIC OR OTHER OFFICER COMPLETING THIS CERTIFICATE VERIFIES ONLY THE IDENTITY OF THE INDIVIDUAL WHO SIGNED THE DOCUMENT TO WHICH THIS CERTIFICATE IS ATTACHED, AND NOT THE TRUTHFULNESS, ACCURACY, OR VALIDITY OF THAT DOCUMENT.

STATE OF CALIFORNIA)
COUNTY OF CONTRA COSTA) SS

ON ____________, 20__, BEFORE ME, ____________________,
A NOTARY PUBLIC, PERSONALLY APPEARED ____________________
WHO PROVED TO ME ON THE BASIS OF SATISFACTORY EVIDENCE TO BE THE PERSON(S) WHOSE NAME(S) IS/ARE SUBSCRIBED TO THE WITHIN INSTRUMENT AND ACKNOWLEDGED TO ME THAT HE/SHE/THEY EXECUTED THE SAME IN HIS/HER/THEIR AUTHORIZED CAPACITY(IES), AND THAT BY HIS/HER/THEIR SIGNATURE(S) ON THE INSTRUMENT THE PERSON(S), OR THE ENTITY UPON BEHALF OF WHICH THE PERSON(S) ACTED, EXECUTED THE INSTRUMENT.

I CERTIFY UNDER PENALTY OF PERJURY UNDER THE LAWS OF THE STATE OF CALIFORNIA THAT THE FOREGOING IS TRUE AND CORRECT.

WITNESS MY HAND

SIGNATURE NOTARY: ____________________

NAME (PRINTED OR TYPED): ____________________

MY COMMISSION EXPIRES: ____________________

COUNTY OF NOTARY: ____________________

PRINCIPAL PLACE OF BUSINESS: ____________________

COUNTY RECORDER'S STATEMENT

THIS MAP ENTITLED "SUBDIVISION MS 19-0007" IS HEREBY ACCEPTED FOR RECORDATION SHOWING A CLEAR TITLE PER LETTER OF TITLE WRITTEN BY FIDELITY NATIONAL TITLE COMPANY, DATED ____________, AND AFTER EXAMINING THE SAME, I DEEM THAT SAID MAP COMPLIES IN ALL RESPECTS WITH THE PROVISIONS OF STATE LAW AND LOCAL ORDINANCES GOVERNING THE FILING OF SUBDIVISION MAPS.

FILED THIS ___ DAY OF ________, 20__, AT _____ __M. IN BOOK _____ OF PARCEL MAPS, AT PAGE ____, AT THE REQUEST OF FIDELITY NATIONAL TITLE COMPANY.

DEBORAH COOPER
COUNTY RECORDER
COUNTY OF CONTRA COSTA
STATE OF CALIFORNIA

BY: ____________________
DEPUTY COUNTY RECORDER

PARCEL MAP
SUBDIVISION MS 19-0007

BEING A SUBDIVISION OF THAT PARCEL OF LAND DESCRIBED IN THE DOCUMENT 2019-076767, AND BEING A PORTION OF LOT 4 AS SHOWN ON THE MAP OF THE NORRIS ADDITION TO WALNUT HEIGHTS (7 M 174)
CONTRA COSTA COUNTY, CALIFORNIA

APEX CIVIL ENGINEERING & LAND SURVEYING
817 Arnold Drive, Ste. 50
Martinez, CA 94553
Ph: (925) 476-8499
www.apexce.net

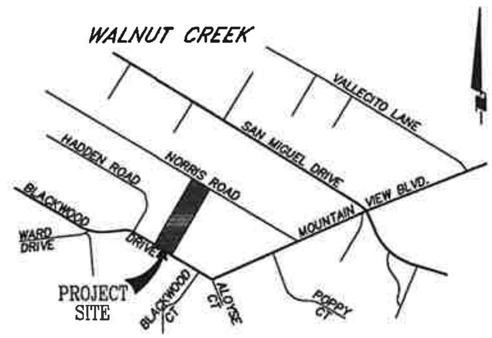
JANUARY, 2022

SURVEYOR'S STATEMENT

THIS MAP CORRECTLY REPRESENTS A SURVEY, MADE BY ME OR UNDER MY DIRECTION, IN CONFORMANCE WITH THE REQUIREMENTS OF THE SUBDIVISION MAP ACT AND LOCAL ORDINANCE AT THE REQUEST OF CAMPOS DEVELOPMENT IN JULY OF 2019. I HEREBY STATE THAT THIS PARCEL MAP SUBSTANTIALLY CONFORMS TO THE APPROVED OR CONDITIONAL APPROVED TENTATIVE MAP, IF ANY. ALL MONUMENTS SHOWN HEREON ACTUALLY EXIST AND ARE SUFFICIENT TO ENABLE THE SURVEY TO BE RETRACED.

BOB J. LEZCANO, LS 8514 ____________ DATED ____________

LICENSED LAND SURVEYOR BOB J. LEZCANO NO. 8514 STATE OF CALIFORNIA



VICINITY MAP
NOT TO SCALE

ZONING ADMINISTRATOR'S STATEMENT

I HEREBY STATE THAT THE BOARD OF SUPERVISORS OF THE COUNTY OF CONTRA COSTA, STATE OF CALIFORNIA, HAS APPROVED THE TENTATIVE MAP OF THIS SUBDIVISION UPON WHICH THIS PARCEL MAP IS BASED.

ARUNA BHAT
DEPUTY DIRECTOR
DEPARTMENT OF CONSERVATION AND DEVELPOMENT
COMMUNITY DEVELOPMENT DIVISION

BY: ____________ DATE: ____________

CLERK OF THE BOARD OF SUPERVISORS' CERTIFICATE

STATE OF CALIFORNIA,
CONTRA COSTA COUNTY

I, MONICA NINO CLERK OF THE BOARD OF SUPERVISORS AND COUNTY ADMINISTRATOR OF CONTRA COSTA, STATE OF CALIFORNIA, DO HEREBY CERTIFY THAT THE ABOVE AND FOREGOING MAP ENTITLED "PARCEL MAP SUBDIVISION MS 19-0007" WAS PRESENTED TO SAID BOARD OF SUPERVISORS, AS PROVIDED BY LAW, AT A REGULAR MEETING THEREOF HELD ON THE _____ DAY OF ____________, 20___, AND THAT SAID BOARD OF SUPERVISORS DID THEREUPON BY RESOLUTION DULY PASSED AND ADOPTED AT SAID MEETING APPROVE SAID MAP.

I FURTHER CERTIFY THAT ALL TAX LIENS HAVE BEEN SATISFIED AND THAT ALL BONDS AS REQUIRED BY LAW TO ACCOMPANY THE WITHIN MAP HAVE BEEN APPROVED BY THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, AND FILED IN MY OFFICE.

IN WITNESS WHEREOF, I HAVE HEREUNTO SET MY HAND THIS DAY _____ OF ____________, 20___

MONICA NINO
CLERK OF THE BOARD OF SUPERVISORS AND
COUNTY ADMINISTRATOR
CONTRA COSTA COUNTY
STATE OF CALIFORNIA

BY: ____________
DEPUTY CLERK

COUNTY SURVEYOR'S STATEMENT

THIS MAP WAS EXAMINED BY ME AND IS SUBSTANTIALLY THE SAME AS IT APPEARS ON THE TENTATIVE MAP, AND ANY APPROVED ALTERATIONS THEREOF. ALL PROVISIONS OF THE SUBDIVISION MAP ACT AND OF ANY LOCAL ORDINANCES APPLICABLE AT THE TIME OF APPROVAL OF THE TENTATIVE MAP HAVE BEEN COMPLIED WITH, AND I AM SATISFIED THAT THE SAME IS TECHNICALLY CORRECT.

DATE: ____________ BY: ____________
JAMES A. STEIN, LS 6571
COUNTY SURVEYOR

PARCEL MAP
SUBDIVISION MS 19-0007

BEING A SUBDIVISION OF THAT PARCEL OF LAND DESCRIBED IN THE DOCUMENT 2019-076767, AND BEING A PORTION OF LOT 4 AS SHOWN ON THE MAP OF THE NORRIS ADDITION TO WALNUT HEIGHTS (7 M 174)

CONTRA COSTA COUNTY, CALIFORNIA

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817 Arnold Drive, Ste. 50
Martinez, CA 94553
Ph: (925) 476-8499
www.apexce.net

JANUARY, 2022 SCALE: 1"=60'

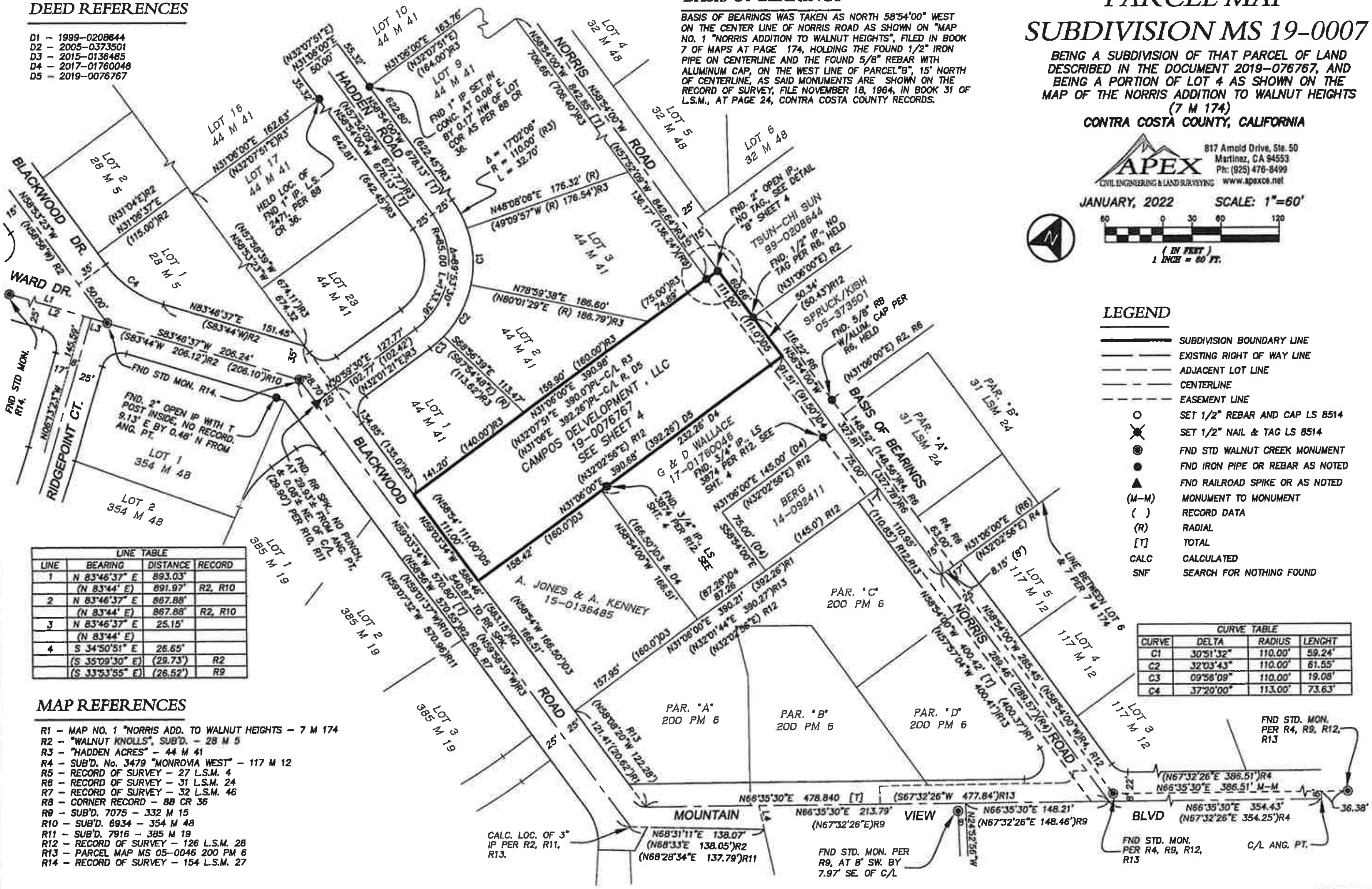
(IN FEET)
1 INCH = 60 FT.

BASIS OF BEARINGS

BASIS OF BEARINGS WAS TAKEN AS NORTH 58°54'00" WEST ON THE CENTER LINE OF NORRIS ROAD AS SHOWN ON "MAP NO. 1 "NORRIS ADDITION TO WALNUT HEIGHTS", FILED IN BOOK 7 OF MAPS AT PAGE 174, HOLDING THE FOUND 1/2" IRON PIPE ON CENTERLINE AND THE FOUND 5/8" REBAR WITH ALUMINUM CAP, ON THE WEST LINE OF PARCEL "B", 15' NORTH OF CENTERLINE, AS SAID MONUMENTS ARE SHOWN ON THE RECORD OF SURVEY, FILE NOVEMBER 18, 1964, IN BOOK 31 OF L.S.M., AT PAGE 24, CONTRA COSTA COUNTY RECORDS.

DEED REFERENCES

D1 – 1999-0208644
D2 – 2005-0373501
D3 – 2015-0136485
D4 – 2017-01760048
D5 – 2019-0076767



CURVE	DELTA	RADIUS	LENGHT
C1	30°51'32"	110.00'	59.24'
C2	32°03'43"	110.00'	61.55'
C3	09°58'09"	110.00'	19.08'
C4	37°20'00"	113.00'	73.63'

LINE	BEARING	DISTANCE	RECORD
1	N 83°46'37" E	893.03'	
	(N 83°44' E)	891.97'	R2, R10
2	N 83°46'37" E	867.88'	
	(N 83°44' E)	867.88'	R2, R10
3	N 83°46'37" E	25.15'	
	(N 83°44' E)		
4	S 34°50'51" E	26.65'	
	(S 35°09'30" E)	(29.73')	R2
	(S 33°53'55" E)	(26.52')	R9

LEGEND

	SUBDIVISION BOUNDARY LINE
	EXISTING RIGHT OF WAY LINE
	ADJACENT LOT LINE
	CENTERLINE
	EASEMENT LINE
○	SET 1/2" REBAR AND CAP LS 8514
	SET 1/2" NAIL & TAG LS 8514
	FND STD WALNUT CREEK MONUMENT
●	FND IRON PIPE OR REBAR AS NOTED
▲	FND RAILROAD SPIKE OR AS NOTED
(M–M)	MONUMENT TO MONUMENT
( )	RECORD DATA
(R)	RADIAL
[T]	TOTAL
CALC	CALCULATED
SNF	SEARCH FOR NOTHING FOUND

MAP REFERENCES

R1 – MAP NO. 1 "NORRIS ADD. TO WALNUT HEIGHTS – 7 M 174
R2 – "WALNUT KNOLLS", SUB'D. – 28 M 5
R3 – "HADDEN ACRES" – 44 M 41
R4 – SUB'D. No. 3479 "MONROVIA WEST" – 117 M 12
R5 – RECORD OF SURVEY – 27 L.S.M. 4
R6 – RECORD OF SURVEY – 31 L.S.M. 24
R7 – RECORD OF SURVEY – 32 L.S.M. 46
R8 – CORNER RECORD – 88 CR 36
R9 – SUB'D. 7075 – 332 M 15
R10 – SUB'D. 6934 – 354 M 48
R11 – SUB'D. 7916 – 385 M 19
R12 – RECORD OF SURVEY – 126 L.S.M. 28
R13 – PARCEL MAP MS 05-0046 200 PM 6
R14 – RECORD OF SURVEY – 154 L.S.M. 27

PARCEL MAP
SUBDIVISION MS 19-0007

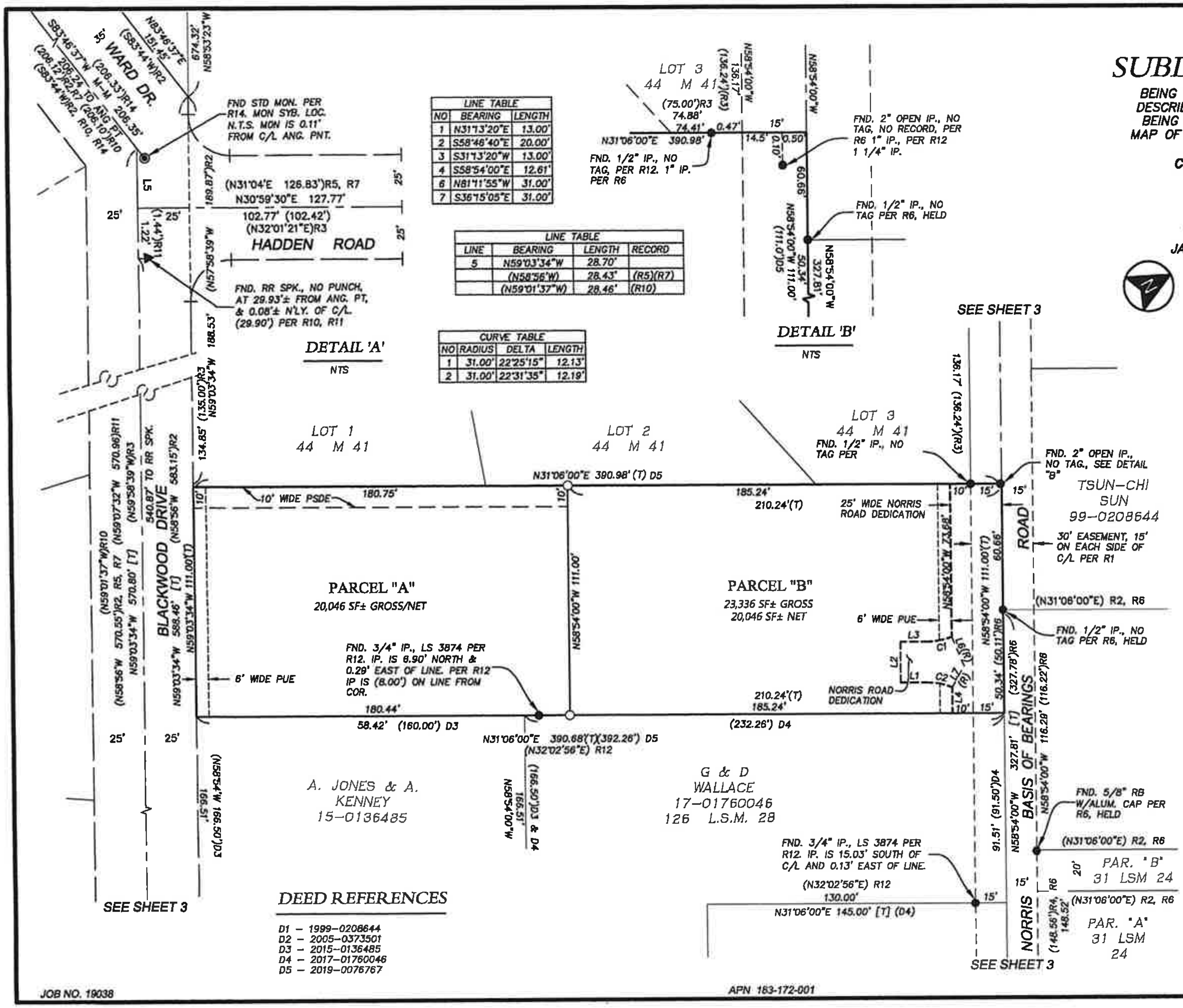
BEING A SUBDIVISION OF THAT PARCEL OF LAND DESCRIBED IN THE DOCUMENT 2019-076767, AND BEING A PORTION OF LOT 4 AS SHOWN ON THE MAP OF THE NORRIS ADDITION TO WALNUT HEIGHTS (7 M 174)

CONTRA COSTA COUNTY, CALIFORNIA

APEX
CIVIL ENGINEERING & LAND SURVEYING
817 Arnold Drive, Ste. 50
Martinez, CA 94553
Ph: (925) 476-8499
www.apexce.net

JANUARY, 2022 SCALE: 1"=30'

(IN FEET)
1 INCH = 30 FT.



LINE TABLE		
NO	BEARING	LENGTH
1	N31°13'20"E	13.00'
2	S58°46'40"E	20.00'
3	S31°13'20"W	13.00'
4	S58°54'00"E	12.61'
6	N81°11'55"W	31.00'
7	S36°15'05"E	31.00'

LINE TABLE			
LINE	BEARING	LENGTH	RECORD
5	N59°03'34"W	28.70'	
	(N58°56'W)	28.43'	(R5)(R7)
	(N59°01'37"W)	28.46'	(R10)

CURVE TABLE			
NO	RADIUS	DELTA	LENGTH
1	31.00'	22°25'15"	12.13'
2	31.00'	22°31'35"	12.19'

LEGEND

- SUBDIVISION BOUNDARY LINE
- EXISTING RIGHT OF WAY LINE
- ADJACENT LOT LINE
- CENTERLINE
- EASEMENT LINE
- SET 1/2" REBAR AND CAP LS 8514
- SET 1/2" NAIL & TAG LS 8514
- FND STD WALNUT CREEK MONUMENT
- FND IRON PIPE OR REBAR AS NOTED
- FND RAILROAD SPIKE OR AS NOTED
- (M-M) MONUMENT TO MONUMENT
- ( ) RECORD DATA
- (R) RADIAL
- [T] TOTAL
- CALC CALCULATED
- SNF SEARCH FOR NOTHING FOUND
- PUE PUBLIC UTILITY EASEMENT
- PSDE PRIVATE STORM DRAIN EASEMENT

MAP REFERENCES

R1 – MAP NO. 1 "NORRIS ADD. TO WALNUT HEIGHTS – 7 L.S.M. 174
R2 – "WALNUT KNOLLS", SUB'D. – 28 M 5
R3 – "HADDEN ACRES" – 44 M 41
R4 – SUB'D. No. 3479 "MONROVIA WEST" – 117 M 12
R5 – RECORD OF SURVEY – 27 L.S.M. 4
R6 – RECORD OF SURVEY – 31 L.S.M. 24
R7 – RECORD OF SURVEY – 32 L.S.M. 46
R8 – CORNER RECORD – 88 CR 36
R9 – SUB'D. 7075 – 332 M 15
R10 – SUB'D. 6934 – 354 M 485
R11 – SUB'D. 7918 – 385 M 19
R12 – RECORD OF SURVEY – 126 L.S.M. 28
R13 – PARCEL MAP MS 05-0046 200 PM 6
R14 – RECORD OF SURVEY – 154 L.S.M. 27

BASIS OF BEARINGS

BASIS OF BEARINGS WAS TAKEN AS NORTH 58°54'00" WEST ON THE CENTER LINE OF NORRIS ROAD AS SHOWN ON "MAP NO. 1 "NORRIS ADDITION TO WALNUT HEIGHTS", FILED IN BOOK 7 OF MAPS AT PAGE 174, HOLDING THE FOUND 1/2" IRON PIPE ON CENTERLINE AND THE FOUND 5/8" REBAR WITH ALUMINUM CAP, ON THE WEST LINE OF PARCEL "B", 15' NORTH OF CENTERLINE, AS SAID MONUMENTS ARE SHOWN ON THE RECORD OF SURVEY, FILE NOVEMBER 18, 1964, IN BOOK 31 OF L.S.M., AT PAGE 24, CONTRA COSTA COUNTY RECORDS.

DEED REFERENCES

D1 – 1999-0208644
D2 – 2005-0373501
D3 – 2015-0136485
D4 – 2017-01760046
D5 – 2019-0076767

JOB NO. 19038

APN 183-172-001

SUBDIVISION AGREEMENT
(Gov. Code, §§ 66462 and 66463)

Subdivision: MS19-0007

Subdivider: Campos Development, LLC

Effective Date: Date approved by BOS

Completion Period: 2 years

THESE SIGNATURES ATTEST TO THE PARTIES' AGREEMENT HERETO:

CONTRA COSTA COUNTY

Brian M. Balbas, Public Works Director

By: ____________________

RECOMMENDED FOR APPROVAL:

By: ____________________

Engineering Services Division

FORM APPROVED: Silvano B. Marchesi, County Counsel

SUBDIVIDER

Campos Devlopment, LLC

Print Name James Campos

Print Title Managing Member

____

Print Name: ____________________

Print Title: ____________________

[Note: If Subdivider is a corporation, two officers must sign. The first must be the chairman of the board, president or any vice president; the second must be the secretary, assistant secretary, chief financial officer or any assistant treasurer. (Corp. Code, § 313; Civ. Code, § 1190.) If Subdivider is a limited liability company, Subdivider shall sign in the manner required of corporations, or by two managers, or by one manager, pursuant to the articles of organization (see Corp. Code, §§17151, 17154, 17157.) If Subdivider is a partnership, any authorized partner may sign. Signatures by Subdivider must be notarized.]

---

1. PARTIES & DATE. Effective on the above date, the County of Contra Costa, California (hereinafter "County"), and the above-mentioned Subdivider mutually promise and agree as follows concerning this Subdivision:

2. IMPROVEMENTS. Subdivider agrees to install certain road improvements (both public and private), drainage improvements, signs, street lights, fire hydrants, landscaping and such other improvements (including appurtenant equipment) as required in the improvement plans for this Subdivision as reviewed and on file with the Contra Costa County Public Works Department, as required by the Conditions of Approval for this Subdivision, and in conformance with the Contra Costa County Ordinance Code, including future amendments thereto (hereinafter "Ordinance Code").

Subdivider shall complete said improvements (hereinafter "Work") within the above completion period from date hereof, as required by the California Subdivision Map Act (Gov. Code, §§ 66410 et. seq.) in a good workmanlike manner, in accordance with accepted construction practices and in a manner equal or superior to the requirements of the Ordinance Code and rulings made thereunder; and where there is a conflict among the improvement plans, the Conditions of Approval and the Ordinance Code, the stricter requirements shall govern.

3. IMPROVEMENTS SECURITY. Upon executing this Agreement, the Subdivider shall, pursuant to Gov. Code § 66499 and the County Ordinance Code, provide as security to the County:

A. For Performance and Guarantee: $ 1000.00 cash, plus additional security, in the amount of $ 80,000.00, which together total one hundred percent (100%) of the estimated cost of the Work. Such additional security is presented in the form of:

__________ Cash, certified check or cashier's check.
__________ Acceptable corporate surety bond.
__________ Acceptable irrevocable letter of credit.

With this security, Subdivider guarantees performance under this Agreement and maintenance of the Work for one year after its completion and acceptance against any defective workmanship or materials or any unsatisfactory performance.

B. For Payment: Security in the amount: $ 40,500.00, which is fifty percent (50%) of the estimated cost of the Work. Such security is presented in the form of:

__________ Cash, certified check, or cashier's check
__________ Acceptable corporate surety bond.
__________ Acceptable irrevocable letter of credit.

With this security, Subdivider guarantees payment to the contractor, to its subcontractors and to persons renting equipment or furnishing labor or materials to them or to the Subdivider.

Upon acceptance of the Work as complete by the Board of Supervisors and upon request of Subdivider, the amounts held as security may be reduced in accordance with Sections 94-4.406 and 94-4.408 of the Ordinance Code.

4. GUARANTEE AND WARRANTY OF WORK. Subdivider guarantees that the Work shall be free from defects in material or workmanship and shall perform satisfactorily for a period of one (1) year from and after the Board of Supervisors accepts the Work as complete in accordance with Article 96-4.6, "Acceptance," of the Ordinance Code. Subdivider agrees to correct, repair, or replace, at Subdivider's expense, any defects in said Work.

The guarantee period does not apply to road improvements for private roads that are not to be accepted into the County road system.

5. PLANT ESTABLISHMENT WORK. Subdivider agrees to perform plant establishment work for landscaping installed under this Agreement. Said plant establishment work shall consist of adequately watering plants, replacing unsuitable plants, doing weed, rodent and other pest control and other work determined by the Public Works Department to be necessary to ensure establishment of plants. Said plant establishment work shall be performed for a period of one (1) year from and after the Board of Supervisors accepts the Work as complete.

6. IMPROVEMENT PLAN WARRANTY. Subdivider warrants the improvement plans for the Work are adequate to accomplish the Work as promised in Section 2 and as required by the Conditions of Approval for the Subdivision. If, at any time before the Board of Supervisors accepts the Work as complete or during the one year guarantee period, said improvement plans prove to be inadequate in any respect, Subdivider shall make whatever changes are necessary to accomplish the Work as promised.

7. NO WAIVER BY COUNTY. Inspection of the Work and/or materials, or approval of the Work and/or materials or statement by any officer, agent or employee of the County indicating the Work or any part thereof complies with the requirements of this Agreement, or acceptance of the whole or any part of said Work and/or materials, or payments therefor, or any combination or all of these acts, shall not relieve the Subdivider of its obligation to fulfill this Agreement as prescribed; nor shall the County be thereby stopped from bringing any action for damages arising from the failure to comply with any of the terms and conditions hereof.

8. INDEMNITY. Subdivider shall defend, hold harmless and indemnify the indemnitees from the liabilities as defined in this section:

A. The indemnitees benefitted and protected by this promise are the County and its special districts, elective and appointive boards, commissions, officers, agents and employees.

B. The liabilities protected against are any liability or claim for damage of any kind allegedly suffered, incurred or threatened because of actions defined below, and including personal injury, death, property damage, inverse condemnation, or any combination of these, and regardless of whether or not such liability, claim or damage was unforeseeable at any time before County reviewed said improvement plans or accepted the Work as complete, and including the defense of any suit(s), action(s), or other proceeding(s) concerning said liabilities and claims.

C. The actions causing liability are any act or omission (negligent or non-negligent) in connection with the matters covered by this Agreement and attributable to Subdivider, contractor, subcontractor, or any officer, agent, or employee of one or more of them.

D. Non-Conditions. The promise and agreement in this section are not conditioned or dependent on whether or not any indemnitee has prepared, supplied, or approved any plan(s) or specification(s) in connection with this Work or Subdivision, or has insurance or other indemnification covering any of these matters, or that the alleged damage resulted partly from any negligent or willful misconduct of any indemnitee.

9. COSTS. Subdivider shall pay, when due, all the costs of the Work, including but not limited to the costs of relocations of existing utilities required thereby; inspections; material checks and tests; and other costs incurred by County staff arising from or related to the Work, and prior to acceptance of the Work as complete or expiration of any applicable warranty periods, whichever is later.

10. SURVEYS. Subdivider shall set and establish survey monuments in accordance with the filed map and to the satisfaction of the County Road Commissioner-Surveyor before acceptance of the Work as complete by the Board of Supervisors.

11. NON-PERFORMANCE AND COSTS. If Subdivider fails to complete the Work within the time specified in this Agreement, and subsequent extensions, or fails to maintain the Work, County may proceed to complete and/or maintain the Work by contract or otherwise and Subdivider agrees to pay all costs and charges incurred by County (including, but not limited to, engineering, inspection, surveys, contract, overhead, etc.) immediately upon demand.

Once action is taken by County to complete or maintain the Work, Subdivider agrees to pay all costs incurred by County, even if Subdivider subsequently completes the Work.

Should County sue to compel performance under this Agreement or to recover costs incurred in completing or maintaining the Work, Subdivider agrees to pay all attorney's fees, staff costs and all other expenses of litigation incurred by County in connection therewith, even if Subdivider subsequently proceeds to complete the Work.

12. INCORPORATION/ANNEXATION. If, before the Board of Supervisors accepts the Work as complete, the Subdivision is included in territory incorporated as a city or is annexed to an existing city, except as provided in this paragraph, County's rights under this Agreement and/or any deposit, bond, or letter of credit securing said rights shall be transferred to the new or annexing city. Such city shall have all the rights of a third party beneficiary against Subdivider, who shall fulfill all the terms of this Agreement as though Subdivider had contracted with the city originally. The provisions of paragraph 8 (Indemnity) shall continue to apply in favor of the indemnitees listed in paragraph 8.A. upon any such incorporation or annexation.

13. RECORD MAP. In consideration hereof, County shall allow Subdivider to file and record the final map or parcel map for said Subdivision.

14. RIGHT OF ENTRY. Subdivider hereby consents to entry onto the Subdivision property, and onto any other property over which Subdivider has land rights and upon which any portion of the Work is to be installed pursuant to the improvement plans, by County and its forces, including contractors, for the purpose of inspection, and, in the event of non-performance of this Agreement by Subdivider, completion and/or maintenance of the Work.

CALIFORNIA CERTIFICATE OF ACKNOWLEDGMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)

County of Sonoma)

On March 8, 2022 before me, Carly Talbott, Notary Public, (here insert name and title of the officer)

personally appeared James Campos

,

who proved to me on the basis of satisfactory evidence to be the person~~(s)~~ whose name~~(s)~~ is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature~~(s)~~ on the instrument the person~~(s)~~, or the entity upon behalf of which the person~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature Carly Talbott

CARLY TALBOTT
COMM. # 2251253
NOTARY PUBLIC • CALIFORNIA
SONOMA COUNTY
My Comm. Exp. July 27, 2022
GSN1

(Seal)

Optional Information

Although the information in this section is not required by law, it could prevent fraudulent removal and reattachment of this acknowledgment to an unauthorized document and may prove useful to persons relying on the attached document.

Description of Attached Document

The preceding Certificate of Acknowledgment is attached to a document titled/for the purpose of ______

______,

containing ______ pages, and dated ______.

The signer(s) capacity or authority is/are as:

- ☐ Individual(s)
- ☐ Attorney-in-Fact
- ☐ Corporate Officer(s) ______ Title(s)
- ☐ Guardian/Conservator
- ☐ Partner - Limited/General
- ☐ Trustee(s)
- ☐ Other: ______

representing: ______ Name(s) of Person(s) or Entity(ies) Signer is Representing

______.

Additional Information

Method of Signer Identification

Proved to me on the basis of satisfactory evidence:
○ form(s) of identification ○ credible witness(es)

Notarial event is detailed in notary journal on:
Page # ______ Entry # ______

Notary contact: ______

Other

☐ Additional Signer(s) ☐ Signer(s) Thumbprint(s)

☐ ______

Subdivision: MS 19-0007

Bond No.: 60008856

Premium: $2,400.00

Any claim under this Bond should be sent to the following address:

Hudson Insurance Company

100 William Street, 5th Floor

New York, NY 10038

IMPROVEMENT SECURITY BOND
FOR SUBDIVISION AGREEMENT
(Performance, Guarantee and Payment)
(Gov. Code, §§ 66499-66499.10)

1. **RECITAL OF SUBDIVISION AGREEMENT.** The Principal has executed an agreement with the County of Contra Costa (hereinafter "County") to install and pay for street, drainage and other improvements in Subdivision MS19-0007 as specified in the Subdivision Agreement, and to complete said work within the time specified for completion in the Subdivision Agreement, all in accordance with State and local laws and rulings thereunder in order to satisfy conditions for filing of the Final Map or Parcel Map for said subdivision. Under the terms of the Subdivision Agreement, Principal is required to furnish a bond to secure the faithful performance of the Subdivision Agreement and payment to laborers and materialmen.

2. **OBLIGATION.** Campos Development, LLC, as Principal, and Hudson Insurance Company, a corporation organized and existing under the laws of the State of Delaware and authorized to transact surety business in California, as Surety, hereby jointly and severally bind ourselves, our heirs, executors, administrators, successors and assigns to the County of Contra Costa, California to pay it:

(A. Performance and Guarantee) eighty thousand and no/xx Dollars ($ 80,000.00) for itself or any city assignee under the above Subdivision Agreement.

(B. Payment) forty thousand five hundred and no/xx Dollars ($ 40,500.00) to secure the claims to which reference is made in Title XV (commencing with Section 3082) of Part 4 of Division III of the Civil Code of the State of California.

3. **CONDITION.** This obligation is subject to the following condition.

A. The condition of this obligation as to Section 2.(A) above is such that if the above bounded Principal, his or its heirs, executors, administrators, successors or assigns, shall in all things stand to and abide by, and well and truly keep and perform the covenants, conditions and provisions in the said agreement and any alteration thereof made as therein provided, on his or their part, to be kept and performed at the time and in the manner therein specified, and in all respects according to their true intent and meaning, and shall indemnify and save harmless the County of Contra Costa (or city assignee), its officers, agents and employees, as therein stipulated, then this obligation shall become null and void; otherwise it shall be and remain in full force and effect.

As part of the obligation secured hereby and in addition to the face amount specified therefor, there shall be included costs and reasonable expenses and fees, including reasonable attorney's fees, incurred by the County of Contra Costa (or city assignee) in successfully enforcing such obligation, and to be taxed as costs and included in any judgment rendered.

B. The condition of this obligation, as to Section 2.(B) above, is such that said Principal and the undersigned as corporate surety are held firmly bound unto the County of Contra Costa and all contractors, subcontractors, laborers, materialmen and other persons employed in the performance of the aforesaid Subdivision Agreement and referred to in the aforesaid Civil Code for materials furnished or labor thereon of any kind, or for amounts due under the Unemployment Insurance Act with respect to this work or labor, and that the Surety will pay the same in an amount not exceeding the amount hereinabove set forth, and also in case suit is brought upon this bond, will pay, in addition to the face amount thereof, costs and reasonable expenses and fees, including reasonable attorney's fees, incurred by the County of Contra Costa (or city assignee) in successfully enforcing such obligation, to be awarded and fixed by the court, and to be taxed as costs and to be included in the judgment therein rendered.

It is hereby expressly stipulated and agreed that this bond shall inure to the benefit of any and all persons, companies, and corporations entitled to file claims under Title 15 (commencing with Section 3082) of Part 4 of Division 3 of the Civil Code, so as to give a right of action to them or their assigns in any suit brought upon this bond.

Should the condition of this bond be fully performed, then this obligation shall become null and void; otherwise it shall be and remain in full force and effect.

C. No change, extension of time, alteration, or addition to the terms of said Subdivision Agreement or the work to be performed thereunder or any plan or specifications of said work, agreed to by the Principal and the County of Contra Costa (or city assignee) shall relieve any Surety from liability on this bond; and consent is hereby given to make such change, extension of time, alteration or addition without further notice to or consent by Surety; and Surety hereby waives the provisions of Civil Code Section 2819 and holds itself bound without regard to and independently of any action against the Principal whenever taken.

SIGNED AND SEALED on March 18, 2022.

Principal: [signature]	Surety: Hudson Insurance Company
Address: 1555 Bothelo Dr. #421	Address: 100 William Street, 5th Floor
Walnut Creek, CA Zip: 94596	New York, NY Zip: 10038
By: Campos Development, LLC	By: [signature]
Print Name: James Campos	Print Name: David Gonsalves
Title: Managing member	Title: Attorney in fact

[Note: All signatures must be acknowledged. For corporations, two officers must sign. The first signature must be that of the chairman of the board, president, or vice-president; the second signature must be that of the secretary, assistant secretary, chief financial officer, or assistant treasurer. (Civ. Code, § 1190 and Corps. Code, § 313.)]

Form Approved by County Counsel
(Rev. 1/06)

H:\FinalAPW\ImpSecBond.1.06.wpd

See Attached
for
Notarization

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT CIVIL CODE § 1189

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California)
County of Contra Costa)

On 4/12/2022 before me, Megan Dennis, Notary Public,
Date — *Here Insert Name and Title of the Officer*

personally appeared James Campos
Name(s) of Signer(s)

______________________________,

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

MEGAN DENNIS
Notary Public - California
Contra Costa County
Commission # 2370288
My Comm. Expires Aug 10, 2025

Signature Megan Dennis
Signature of Notary Public

Place Notary Seal Above

OPTIONAL

Though this section is optional, completing this information can deter alteration of the document or fraudulent reattachment of this form to an unintended document.

Description of Attached Document

Title or Type of Document: ______________ Document Date: ______________

Number of Pages: _______ Signer(s) Other Than Named Above: ______________

Capacity(ies) Claimed by Signer(s)

Signer's Name: ______________
☐ Corporate Officer — Title(s): ______________
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______________
Signer Is Representing: ______________

Signer's Name: ______________
☐ Corporate Officer — Title(s): ______________
☐ Partner — ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ______________
Signer Is Representing: ______________

ACKNOWLEDGMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of ~~California~~ North Carolina
County of Mecklenburg)

On 03/18/2022 before me, Elspeth J. Murray, Notary Public
(insert name and title of the officer)

personally appeared David Gonsalves,
who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of ~~California~~ North Carolina that the foregoing paragraph is true and correct.

ELSPETH J. MURRAY
NOTARY PUBLIC
MECKLENBURG COUNTY
NORTH CAROLINA
MY COMMISSION EXPIRES 12/15/2023

WITNESS my hand and official seal.

Signature EJMurray **(Seal)**

Bond Number: 60008856

HUDSON INSURANCE GROUP

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS: That HUDSON INSURANCE COMPANY, a corporation of the State of Delaware, with offices at 100 William Street, New York, New York, 10038, has made, constituted and appointed, and by these presents, does make, constitute and appoint

David Gonsalves

of the State of North Carolina

its true and lawful Attorney(s)-in-Fact, at New York, New York, each of them alone to have full power to act without the other or others, to make, execute and deliver on its behalf, as Surety, bonds and undertakings given for any and all purposes, also to execute and deliver on its behalf as aforesaid renewals, extensions, agreements, waivers, consents or stipulations relating to such bonds or undertakings provided, however, that no single bond or undertaking shall obligate said Company for any portion of the penal sum thereof in excess of the sum of

Eighty Thousand ($80,000.00) **Dollars**

Such bonds and undertakings when duly executed by said Attorney(s)-in-Fact, shall be binding upon said Company as fully and to the same extent as if signed by the President of said Company under its corporate seal attested by its Secretary.

In Witness Whereof, HUDSON INSURANCE COMPANY has caused these presents to be of its Senior Vice President thereunto duly authorized, on this 16th day of November, 20 17 at New York, New York.

(Corporate seal)

SEAL

Attest.........................

Dina Daskalakis
Corporate Secretary

HUDSON INSURANCE COMPANY

By.........................

Michael P. Cifone
Senior Vice President

STATE OF NEW YORK
COUNTY OF NEW YORK. SS.

On the 16th day of November, 20 17 before me personally came Michael P. Cifone to me known, who being by me duly sworn did depose and say that he is a Senior Vice President of **HUDSON INSURANCE COMPANY**, the corporation described herein and which executed the above instrument, that he knows the seal of said Corporation, that the seal affixed to said instrument is such corporate seal, that it was so affixed by order of the Board of Directors of said Corporation, and that he signed his name thereto by like order.

(Notarial Seal)

ANN M. MURPHY NOTARY PUBLIC STATE OF NEW YORK

....
ANN M. MURPHY
Notary Public, State of New York
No. 01MU6067553
Qualified in Nassau County
Commission Expires December 10, 2021

CERTIFICATION

STATE OF NEW YORK
COUNTY OF NEW YORK SS.

The undersigned **Dina Daskalakis** hereby certifies:

That the original resolution, of which the following is a true and correct copy, was duly adopted by unanimous written consent of the Board of Directors of Hudson Insurance Company dated July 27th, 2007, and has not since been revoked, amended or modified:

"RESOLVED, that the President, the Executive Vice Presidents, the Senior Vice Presidents and the Vice Presidents shall have the authority and discretion, to appoint such agent or agents, or attorney or attorneys-in-fact, for the purpose of carrying on this Company's surety business, and to empower such agent or agents, or attorney or attorneys-in-fact, to execute and deliver, under this Company's seal or otherwise, bonds obligations, and recognizances, whether made by this Company as surety thereon or otherwise, indemnity contracts, contracts and certificates, and any and all other contracts and undertakings made in the course of this Company's surety business, and renewals, extensions, agreements, waivers, consents or stipulations regarding undertakings so made; and

FURTHER RESOVLED, that the signature of any such Officer of the Company and the Company's seal may be affixed by facsimile to any power of attorney or certification given for the execution of any bond, undertaking, recognizance, contract of indemnity or other written obligation in the nature thereof or related thereto, such signature and seal when so used whether heretofore or hereafter, being hereby adopted by the Company as the original signature of such officer and the original seal of the Company, to be valid and binding upon the Company with the same force and effect as though manually affixed."

THAT the above and foregoing is a full, true and correct copy of Power of Attorney issued by said Company, and of the whole of the original and that the said Power of Attorney is still in full force and effect and has not been revoked, and furthermore that the Resolution of the Board of Directors, set forth in the said Power of Attorney is now in force.

Witness the hand of the undersigned and the seal of said Corporation this 18th day of March, 2022.

(Corporate seal)

SEAL 1918

By.........................

Dina Daskalakis, Corporate Secretary

4/15/22

Fidelity National $ 47.00

Tax Collector's Office
625 Court Street
Finance Building, Room 100
P. O. Box 631
Martinez, California 94553-0063
(925) 608 - 9500
(925) 608 - 9598 (FAX)

Contra Costa County

Russell V. Watts
County Treasurer-Tax Collector

Lulis Lopez
Assistant Tax Collector

Danielle Goodbar
Tax Operations Supervisor

Date: 3/1/2022

IF THIS TRACT IS NOT FILED PRIOR TO THE DATE TAXES ARE OPEN FOR COLLECTION (R&T CODE 2608) ***THIS LETTER IS VOID.***

This will certify that I have examined the map of the proposed subdivision entitled:

Tract / MS #	**City**	**T.R.A.**
MS 19-0007	**Walnut Creek**	**98002**

Parcel #: 183-172-001-4

and have determined from the official tax records that there are no unpaid County taxes heretofore levied on the property included in the map.

The 2021-2022 tax lien has been paid in full. Our estimate of the 2022-2023 tax lien, which became a Lien on the **1st day of January, 2022** is :

$20,640.00

This tract is not subject to a 1915 Act Bond.

The amount calculated is ***void*** 45 days from the date of this letter, unless this letter is accompanied with security approved by the Contra Costa County Tax Collector
Subdivision bond must be presented to the County Tax Collector for review and approval of adequacy of security prior to filing with the Clerk of the Board of Supervisors.

RUSSEL V. WATTS
Treasurer-Tax Collector
By:

COUNTY OF CONTRA COSTA

ELECTRONIC DEPOSIT PERMIT

OFFICE OF COUNTY AUDITOR-CONTROLLER
MARTINEZ, CALIFORNIA

DEPARTMENT NAME
TREASURER-TAX COLLECTOR

FISCAL YEAR
2021 - 2022

ORGANIZATION NUMBER **15**

DESCRIPTION OF DEPOSIT	FUND/ORG NO.	SUB ACCT	TASK	OPT	ACTIVITY	AMOUNT	TOTAL
SUB-DIV MS 190007 tax collector special - subdivision guarantee	831400	0803				$20,640.00	$20,640.00

TOTAL DEPOSIT: **$20,640.00**

GENERAL DEPOSIT NOTES:

SITE OF DEPOSIT: BANK **ACCOUNT DEPOSITED:** Wells Fargo Bank - Tax Collector
CASH: $0.00 **CHECKS:** $0.00 **BANK DEPOSIT:** $20,640.00

Bank Receipt: SUB-DIV **Date:** 03/21/2022 **NOTES: SUB-DIVISION GUARANTEE MS 19-0007 183-172-001-4**

SECTION 26901 GOVERNMENT CODE
I HEREBY SWEAR THAT THIS IS A
TRUE AND CORRECT RECORD OF THE TOTAL
AMOUNT OF MONEY AS DESCRIBED ABOVE
FOR DEPOSIT INTO THE COUNTY TREASURY

THE A-C OF CCC, HEREBY CERTIFIES
THAT THE AMOUNT DUE THE TREASURER
OF SAID COUNTY FOR MONIES COLLECTED
BY **TREASURER-TAX COLLECTOR**
-WELLS FARGO BANK - TAX COLLECTOR
IN SETTLEMENT OF THE ABOVE DESCRIBED
ACCOUNTS IS THE SUM OF **$20,640.00**

RECEIPT OF ABOVE AMOUNT
IS HEREBY ACKNOWLEDGED.

Mar 21, 202201:24:14PM

Rebbecca Magdaleno (Tax)
USER VALIDATION

NOT PROCESSED

NOT SIGNED
AUDITOR'S VALIDATION

NOT PROCESSED

NOT SIGNED
TTC VALIDATION

USER PHONE NO.

925-957-2808

USER NAME
Rebbecca Magdaleno (Tax)

SUBMIT DATE
Mar 21, 2022 01:24:14PM

EDP NO
DP845781

C.8

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/143

IN THE MATTER OF approving the Parcel Map and Subdivision Agreement for minor subdivision MS19-00007, for a project being developed by Campos Development, LLC, as recommended by the Public Works Director, Walnut Creek area. (District IV)

WHERE AS, the following documents were presented for board approval this date:

I. Map

The Parcel Map of minor subdivision MS19-00007, property located in the Walnut Creek area, Supervisorial District IV, said map having been certified by the proper officials.

II. Subdivision Agreement

A subdivision agreement with Campos Development, LLC, principal, whereby said principal agrees to complete all improvements as required in said subdivision agreement within 2 year(s) from the date of said agreement. Accompanying said subdivision agreement is security guaranteeing completion of said improvements as follows:

A. Cash Bond

Performance amount: $1,000.00

Auditor's Deposit Permit No. DP844778 Date: March 3, 2022

Submitted by: Campos Development, LLC

B. Surety Bond

Bond Company: Hudson Insurance Company

Bond Number: 60008856 Date: March 18, 2022

Performance Amount: $80,000.00

Labor & Materials Amount: $40,500.00

Principal: Campos Development, LLC

III. Tax Letter

Letter from the County Tax Collector stating that there are no unpaid County taxes heretofore levied on the property included in said map and that the 2021-2022 tax lien has been paid in full and the 2022-2023 tax lien, which became a lien on the first day of January 2022, is estimated to be $20,460.00, with security guaranteeing payment of said tax lien as follows:

- Tax Surety

Auditor's Deposit Permit Number: DP845781 Date: March 21, 2022

Amount: $20,460.00

Submitted by/Principal: Campos Development, LLC

NOW, THEREFORE, BE IT RESOLVED:

1. That said subdivision, together with the provisions for its design and improvement, is DETERMINED to be consistent with the County's general and specific plans.

2. That said map is APPROVED and this Board does hereby *accept subject to installation and acceptance of improvements* on behalf of the public any of the streets, paths, or easements shown thereon as dedicated to public use.

3. That said subdivision agreement is also APPROVED.

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Randolf Sanders (925) 313-2111

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

Stacey M Boyd

By: Stacey M. Boyd, Deputy

cc: Larry Gossett- Engineering Services, Randolf Sanders- Engineering Services, Deborah Preciado - Engineering Services, Renee Hutchins - Records, Karen Piona- Records, Dante Morabe - Design & Construction, Chris Hallford -Mapping , Michael Mann- Finance, Chris Lau - Maintenance, Margaret Mitchell- DCD, Campos Development, LLC, Hudson Insurance Company

To: Board of Supervisors

From: John Kopchik, Director, Conservation & Development Department

Date: May 3, 2022

Contra Costa County

Subject: 2022 Bike to Work Day

RECOMMENDATION(S):
ADOPT Resolution No. 2022/147 proclaiming May 2022 as "Bike to Wherever Days" and May 20, 2022 as "Bike to Work Day" in Contra Costa County, and AUTHORIZE the County Administrator to sign a memorandum requesting County Department Heads to participate in outreach efforts to their employees for Bike to Wherever Days and Bike to Work Day.

FISCAL IMPACT:
No fiscal impact. The Metropolitan Transportation Commission and 511.org provide outreach materials, distributed through existing County protocols.

BACKGROUND:
The goal of Bike to Work Day is to encourage County commuters to try bicycling to work on this day by offering a variety of incentives, such as a raffle for prizes and energizer stations with refreshments and educational materials for bicycle commuters throughout the county. The hope is that once individuals try bicycling to work, they will continue to commute by bicycle one or more days a week. Bicycling provides excellent exercise and is a non-polluting and energy-efficient form of transportation.

Due to COVID-19, in 2020 and 2021, Bike to Work Day was rebranded as "Bike to Wherever Days," which promoted bicycling for any purpose, and took place during the entire month of September and May of 2020 and 2021, respectively.

For 2022, the entire month of May will be celebrated as Bike to Wherever Days, while May 20th will be celebrated as Bike to Work Day. All nine Bay Area counties are participating in Bike to Work Day and/or Bike to Wherever Days at some level. The Metropolitan Transportation Commission, with the help of financial donations from event sponsors and volunteers, will primarily fund Bike to Work Day/Bike to Wherever Days in the San Francisco Bay Area. On Bike to Work Day, cyclists can stop for refreshments and promotional materials at over 200 energizer stations throughout the Bay Area, over 35 of which will be located in Contra Costa County. 511 Contra Costa coordinates volunteers to work at energizer stations in Contra Costa County. Additional information on these events is available at this website: https://bayareabiketowork.com.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Robert Sarmiento, (925) 655-2918

cc:

BACKGROUND: (CONT'D)

Attached is a draft transmittal memo (Exhibit A) from the County Administrator to all departments requesting that they encourage their employees to participate in Bike to Work Day and Bike to Wherever Days. With the Board's approval, posters and other outreach materials will be distributed to County departments for their use in outreach to County employees.

CONSEQUENCE OF NEGATIVE ACTION:

The County will not encourage its employees to participate in Bike to Work Day or Bike to Wherever Days.

AGENDA ATTACHMENTS

Resolution 2022/147

Exhibit A- Bike to Work Memo

Exhibit B- Bike to Work Flyer

MINUTES ATTACHMENTS

Signed Resolution No. 2022/147

The Board of Supervisors of
Contra Costa County, California

In the matter of: **Resolution No. 2022/147**

PROCLAIMING MAY 2022 AS "BIKE TO WHATEVER DAYS" AND MAY 20, 2022 AS "BIKE TO WORK DAY"

WHEREAS, breathing clean air is vital to healthy lungs and life; and
WHEREAS, the County of Contra Costa encourages its employees and citizens to bicycle in order to improve air quality and promote the health benefits of bicycling; and
WHEREAS, the County of Contra Costa acknowledges that bicycling to work is a viable commute mode to improve the "livability" of communities by reducing traffic noise and congestion; and
WHEREAS, Bike to Work Days have proven effective in converting drivers into bicyclists and educating citizens about the public health benefits of bicycling to work regularly; and
WHEREAS, due to COVID-19, Bike to Work Day was temporarily rebranded as Bike to Wherever Days in 2020 and 2021, and
WHEREAS Bike to Wherever Days took place over an entire month, and
WHEREAS Bike to Wherever Days encourages bicycling for all types of trips, and
WHEREAS, National Bike Month and California Bike Commute Week are in May; and
WHEREAS, all nine Bay Area counties are participating in Bike to Wherever Days in May and/or Bike to Work Day on May 20, 2022.

NOW, THEREFORE BE IT RESOLVED that the Contra Costa County Board of Supervisors hereby proclaims May 2022 as "Bike to Wherever Days" and May 20, 2022 as "Bike to Work Day" in Contra Costa County.

____
KAREN MITCHOFF
Chair, District IV Supervisor

____
JOHN GIOIA
District I Supervisor

____
CANDACE ANDERSEN
District II Supervisor

____
DIANE BURGIS
District III Supervisor

____
FEDERAL D. GLOVER
District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator

By: ________________________________, Deputy c9

The Board of Supervisors of Contra Costa County, California

In the matter of proclaiming May 2022 as "Bike to Whatever Days" and May 20, 2022, as "Bike to Work Day."

Resolution No. 2022/147

WHEREAS, breathing clean air is vital to healthy lungs and life; and

WHEREAS, the County of Contra Costa encourages its employees and citizens to bicycle in order to improve air quality and promote the health benefits of bicycling; and

WHEREAS, the County of Contra Costa acknowledges that bicycling to work is a viable commute mode to improve the "livability" of communities, by reducing traffic noise and congestion; and

WHEREAS, Bike to Work Days have proven effective in converting drivers into bicyclists while educating citizens about the public health benefits of bicycling to work regularly; and

WHEREAS, due to COVID-19, Bike to Work Day was temporarily rebranded as "Bike to Wherever Days," in 2020 and 2021, and

WHEREAS, Bike to Wherever Days took place over an entire month, and

WHEREAS, Bike to Wherever Days encourages bicycling, for all types of trips, and

WHEREAS, National Bike Month and California Bike Commute Week are in May, and

WHEREAS, all nine Bay Area counties are participating in Bike to Wherever Days in May and/or Bike to Work Day on May 20, 2022; and

NOW, THEREFORE, BE IT RESOLVED that the Board of Supervisors of Contra Costa County does hereby proclaims May 2022 as "Bike to Wherever Days" and May 20, 2022, as "Bike to Work Day," in Contra Costa County.

PASSED by a unanimous vote of the Board of Supervisors members present this 3rd day of May 2022.

KAREN MITCHOFF
Chair,
District IV Supervisor

JOHN GIOIA
District I Supervisor

CANDACE ANDERSEN
District II Supervisor

DIANE BURGIS
District III Supervisor

FEDERAL D. GLOVER
District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown:

ATTESTED: May 3, 2022

MONICA NINO, Clerk of the Board of Supervisors and County Administrator

By ______________________, Deputy

County of Contra Costa

Office of the County Administrator

MEMORANDUM

DATE: May 4, 2022

TO: All Departments

FROM: Monica Nino, County Administrator

SUBJECT: **2022 BIKE TO WHEREVER DAYS AND BIKE TO WORK DAY**

Pull out your bike, pump up the tires, and leave your car in the garage! May is National Bike Month. This year, the Bay Area will be celebrating both "Bike to Wherever Days" for the entire month of May and "Bike to Work Day" on Friday, May 20. The goal of Bike to Wherever Days is to encourage Bay Area residents to ride their bikes for all types of trips, including commute trips, recreational trips, and shopping trips. The goal of Bike to Work Day is to encourage County commuters to try bicycling to work on this day by offering a variety of incentives, such as a raffle for prizes and bicycle energizer stations with refreshments and bicycle educational materials. All nine Bay Area counties will be participating in Bike to Wherever Days and Bike to Work Day at some level. County Departments are being asked to encourage their staff to bike as often as possible during Bike to Wherever Days and ride a bike to work on Bike to Work Day. More information on both Bike to Wherever Days and Bike to Work Day can be found at the following website: https://bayareabiketowork.com.

511 Contra Costa's bicycling website (511contracosta.org/biking) provides bicycling resources to prepare you for Bike to Wherever Days and Bike to Work Day, including a Bike Mapper page (https://bike.511contracosta.org) to help you plan your bike route. 511 Contra Costa has developed a bike safety quiz (https://driveless.typeform.com/BTWDsafety) that all County

employees, including bicyclists and drivers, are encouraged to take. 511 Contra Costa will award prizes to twenty randomly selected people who take the survey.

County Departments are encouraged to participate in outreach efforts to promote both events, including distributing a flyer (attached) promoting an interdepartmental bike competition. The interdepartmental bike competition has been created to see which department will have the highest number of participants on Bike to Work Day. Individual participants can record their 2022 Bike to Work Day participation[1] in a survey (http://tiny.cc/CCC2022BTWDSurvey).[2] Staff from the Department of Conservation and Development will tally the number of participants by department and award prizes to the department with the most participants in Bike to Work Day.[3] All participants are encouraged to post photos of their bike ride and the destinations they biked to on social media, using the hashtag **#CCC2022BTWD**.

A separate Bay Area-wide bike competition, the "Bike Month Challenge," will also be taking place for the entire month of May. Please see the following website for more details, including information on prizes for people who participate in the competition: https://www.lovetoride.net/bayarea/pages/info?locale=en-US.

Staff from both the Department of Conservation and Development and the Public Works Department have volunteered to tune up bikes to help you get ready for both Bike to Wherever Days and Bike to Work Day.[4] Services include help fixing a flat, adjusting brakes and gears, and maintaining bike chains.

For more information on 2022 Bike to Wherever Days and Bike to Work Day, please contact Robert Sarmiento, Department of Conservation and Development, at robert.sarmiento@dcd.cccounty.us or (925) 655-2918.

[1] DCD staff will accept bike rides to work on any workday during the week of May 16-20.

[2] Surveys will be accepted through **Friday, June 3**.

[3] Each department's Bike to Work Day employee participation will be weighted based on the total number of employees in the department.

[4] Contact Joseph Lawlor, Department of Conservation and Development [joseph.lawlor@dcd.cccounty.us, (925) 655-2872)], or Lawrence Leong, Public Works Department [larry.leong@pw.cccounty.us, (925) 313-2026].

BIKE TO WORK DAY MAY 20 2022

Take part in the interdepartmental "Bike to Work Day" Challenge on May 20th and ride your bike to work!* Log your Bike to Work Day ride at http://tiny.cc/CCC2022BTWDSurvey. Giveaways for all participants and a prize will be awarded to the department that has the most participation!**

You are also encouraged to bike often for any type of trip for "Bike to Wherever Days," which is taking place throughout the month of May.

For more information on Bike to Work Day and Bike to Wherever Days, visit https://bayareabiketowork.com, or contact Robert Sarmiento, Department of Conservation and Development, at robert.sarmiento@dcd.cccounty.us or (925) 655-2918.

*Department of Conservation and Development staff will accept bike rides to work on any workday during the week of May 16-20.

**Surveys will be accepted through Friday, June 3.

Contra Costa County

To: Board of Supervisors

From: John Gioia, District I Supervisor

Date: May 3, 2022

Subject: In Recognition of El Cerrito Fire Chief Michael Pigoni's 40 Years of Service

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: James Lyons, 510-942-2222

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

AGENDA ATTACHMENTS

Resolution 2022/166

MINUTES ATTACHMENTS

Signed Resolution No. 2022/166

The Board of Supervisors of
Contra Costa County, California

In the matter of: **Resolution No. 2022/166**

Recognizing El Cerrito Fire Chief Michael Pigoni's 40 Years of Service

WHEREAS, El Cerrito Fire Chief Michael Pigoni has faithfully-served the City of El Cerrito in West Contra Costa County for 27 years with dedication, excellence, and compassion, and on his upcoming retirement is deserving of County recognition; and

WHEREAS, Michael's career began more than 40 years ago with the Geyserville Volunteer Fire Department; and

WHEREAS, Michael has served on the Geyserville Fire Protection District Board of Directors as a Board Member, Treasurer and President for 15 years; and

WHEREAS, Michael has served over 600 people as the Head Chef for Geyserville Volunteer Fire Department dinners and fundraisers and raised more than $80,000 annually for equipment; and

WHEREAS, Michael began his distinguished career at the El Cerrito Fire Department in 1995 as a firefighter, earned promotion to Captain in 2000, earned promotion to Battalion Chief in 2007, and achieved the Department's highest position, Fire Chief, in 2018; and

WHEREAS, Michael has led several strike teams as Strike Team Leader; and

WHEREAS, Michael has worked successfully with the Public Works Department, partnering agencies, and the community to strengthen vegetation management programs, emergency operations, and response plans, thereby enhancing safety and saving lives and property; and

WHEREAS, Michael has served in every rank within the Fire Department and consistently succeeded in empowering others to believe in their abilities, excel in their jobs, advance in rank, and provide professional service to the community; and

WHEREAS, Michael is loved and supported devotedly by his wife Carol and his chocolate Labrador Retriever, Mousse.

NOW THEREFORE, BE IT RESOLVED, that the Board of Supervisors of Contra Costa County does hereby recognize in gratitude El Cerrito Fire Chief Michael Pigoni for his distinguished record of service to the Greater Bay Area, Contra Costa County and the El Cerrito community and extends to him sincere appreciation and best wishes for continued happiness and success in retirement.

____

KAREN MITCHOFF
Chair, District IV Supervisor

____

JOHN GIOIA
District I Supervisor

____

CANDACE ANDERSEN
District II Supervisor

____

DIANE BURGIS
District III Supervisor

____

FEDERAL D. GLOVER
District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator

By: ___________________________________, Deputy

C10

The Board of Supervisors of Contra Costa County, California

In the matter of recognizing El Cerrito Fire Chief Michael Pigoni's 40 Years of Service.

Resolution No. 2022/166

WHEREAS, El Cerrito Fire Chief Michael Pigoni has faithfully served the City of El Cerrito, in West Contra Costa County, for 27 years with dedication, excellence and compassion, and on his upcoming retirement is deserving of County recognition; and

WHEREAS, Michael's career began more than 40 years ago with the Geyserville Volunteer Fire Department; and

WHEREAS, Michael sat on the Geyserville Fire Protection District Board of Directors as a Board Member, Treasurer and President for 15 years; and

WHEREAS, Michael has served, over 600 people, as the Head Chef for Geyserville Volunteer Fire Department dinners and fundraisers, and raised more than $80,000 annually for equipment; and

WHEREAS, Michael began his distinguished career at the El Cerrito Fire Department, in 1995, as a firefighter. He earned promotion to Captain in 2000, advanced to Battalion Chief in 2007 and achieved the Department's highest position, Fire Chief, in 2018; and

WHEREAS, Michael has led several strike teams, as Strike Team Leader; and

WHEREAS, Michael worked successfully with the Public Works Department, partnering agencies and the community to strengthen vegetation management programs, emergency operations and response plans, thereby enhancing safety, saving lives and property; and

WHEREAS, Michael has served in every rank, within the Fire Department, and consistently succeeded in empowering others to believe in their abilities, excel in their jobs, advance in rank and provide professional service to the community; and

WHEREAS, Michael is loved and supported devotedly by his wife, Carol, and his chocolate Labrador Retriever, Mousse; and

NOW, THEREFORE, BE IT RESOLVED that the Board of Supervisors of Contra Costa County does hereby recognize in gratitude El Cerrito Fire Chief Michael Pigoni for his distinguished record of service to the Greater Bay Area, Contra Costa County and the El Cerrito community and extends to him sincere appreciation and best wishes for continued happiness and success in retirement.

PASSED by a unanimous vote of the Board of Supervisors members present this 3rd day of May 2022.

Karen Mitchoff

KAREN MITCHOFF
Chair,
District IV Supervisor

JOHN GIOIA
District I Supervisor

CANDACE ANDERSEN
District II Supervisor

DIANE BURGIS
District III Supervisor

FEDERAL D. GLOVER
District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown:

ATTESTED: May 3, 2022

MONICA NINO, Clerk of the Board of Supervisors and County Administrator

By ______________________, Deputy

Contra Costa County

To: Board of Supervisors

From: John Kopchik, Director, Conservation & Development Department

Date: May 3, 2022

Subject: Appointments to the Historical Landmarks Advisory Committee (HLAC)

RECOMMENDATION(S):

APPOINT Mr. David Yuers to Seat 2 and Mr. Anthony Geisler to Seat 3 on the Historical Landmarks Advisory Committee for the remainder of the 4-year term that expires August 12, 2022, as recommended by the Contra Costa County Historical Society.

Mr. David Yuers - Walnut Creek, zip code: 94596

Mr. Anthony Geisler - Diablo, zip code: 94528

FISCAL IMPACT:

None.

BACKGROUND:

The Historical Landmarks Advisory Committee (HLAC) has five members, comprised of four members of the Contra Costa County Historical Society, and the Department of Conservation and Development Director or Designee serves as the fifth member.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Dominique Vogelpohl, HLAC staff, (925) 655-2880

cc:

BACKGROUND: (CONT'D)

Both appointees' applications are on file with the Clerk of the Board of Supervisors.

Attached is the letter from the Contra Costa County Historical Society's President, John A. Burgh, stating the Historical Society unanimously recommends Mr. David Yuers and Mr. Anthony Geisler to the two vacant seats of the HLAC.

Terms are 48 months, and both seats' term expires August 12, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If the Board does not act, the the HLAC will continue to have two vacant seats, which has hindered their effectiveness as an advisory body.

ATTACHMENTS

CCC Historical Society Letter of Recommendation

Contra Costa County Historical Society

ESTABLISHED APRIL 30, 1951

March 19, 2022

Mr. Dominique Vogelphol
Department of Conservation & Development
Contra Costa County
1025 Escobar St.
Martinez, CA 94553

Re: Nomination of candidates for HLAC vacant positions

Dear Mr: Vogelphol:

On March 17, 2022, the Board of Directors of the Contra Costa County Historical Society voted unanimously to nominate Mr. Anthony Geisler of Diablo and Mr. David Yuers of Walnut Creek to the two presently vacant positions on the Historical Landmark Advisory Committee.

If you have any questions, kindly let me know, at your convenience.

Very truly yours,

John A. Burgh
President

CONTRA COSTA COUNTY HISTORICAL SOCIETY 724 ESCOBAR STREET, MARTINEZ, CA 94553-1114
TEL: (925) 229-1042 FAX: (925) 229-1772 E-MAIL: info@cocohistory.org WEBSITE: www.cocohistory.org

To: Board of Supervisors

From: Russell Watts, Treasurer-Tax Collector

Date: May 3, 2022

Contra Costa County

Subject: APPOINTMENT OF SPECIAL DISTRICTS REPRESENTATIVE TO THE TREASURY OVERSIGHT COMMITTEE

RECOMMENDATION(S):

REAPPOINT Philip Leiber to the Category 2 Seat, a statutory member representing legislative bodies of the special districts in the County, for a second four-year term on the Treasury Oversight Committee. Term May 1, 2022 - April 30, 2026.

FISCAL IMPACT:

None.

BACKGROUND:

The Board of Supervisors established the Treasury Oversight Committee on November 14, 1995, pursuant to Chapter 5, Article 6 of the California Government Code. The purpose of the Treasury Oversight Committee is to review and monitor the County Treasurer's annual investment policy, and to ensure an annual audit is conducted to determine the County's compliance with Government Code §§ 27130-27137.

The Committee will be composed of seven statutory members and three alternates. The Committee members fall in one of three different categories as follows:

Category 1: Appointed officials (two statutory members and one alternate). Category 1 appointed members are the County Superintendent of Schools or his or her designee and

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

Contact: Ronda Boler (925) 608-9506

cc:

BACKGROUND: (CONT'D)

a representative and an alternate of the Board or their designee.

Category 2: Elected members (two statutory members and two alternates). Category 2 includes one representative and one alternate elected by a majority of the school and community college districts; and one representative and one alternate elected by a majority of the special districts.

Category 3: Public members (three statutory members). Category 3 includes representatives from the public nominated by the County Treasurer and confirmed by the Board.

On January 27, 2020, Philip Leiber, Director of Finance and Administration at the Central Costa Costa Sanitary District, was elected to the Special District Representative seat on the Treasury Oversight Committee. Mr. Leiber was re-elected by unanimous vote of the Contra Costa Special Districts Association Executive Committee on April 11, 2022 to serve a second term, May 1, 2022 - April 30, 2026, as the Primary Special District Member appointee to the Treasury Oversight Committee.

CONSEQUENCE OF NEGATIVE ACTION:

No continuous representation by the legislative bodies of the special districts in the County on the Treasury Oversight Committee as required by California Government Code section 27132 and the November 14, 1995, County Board Order (I.O.-4) regarding composition of a County Treasury Oversight Committee.

ATTACHMENTS

TOC Appointment_Philip Leiber

CCSDA
Contra Costa Special Districts Association

CCSDA OFFICERS

Chad Davisson
Chapter President

Susan Morgan
Chapter Vice President

Stan Caldwell
Past President

Michael McGill
Member at Large

Daniel Muelrath
Member at Large

April 19, 2022,

Ms. Ronda Boler
Treasurer – Tax Collector's Office
625 Court Street, Room 100
Martinez, CA 94553

Ms. Boler,

This is to inform you that Philip Lieber, Central Contra Costa Sanitary District, has been named Primary Special District Member appointee to the Treasury Oversight Committee by a unanimous vote of the Contra Costa Special Districts Association Executive Committee at our April 11, 2022 meeting.

The CCSDA Executive Committee is in the process of identifying an alternate, as Stephen Smith, the current alternate is with the East Contra Costa Fire Protection District and they are consolidating with Con-Fire and will no longer be a special district entity. We will notify you when we identify and appoint an alternate.

If you have any questions, please give me a call at (925) 727-2938.

Respectfully,

Chad Davisson

Chad Davisson

Contra
Costa
County

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Subject: Purchase of vehicle for the Senior Nutrition Program

RECOMMENDATION(S):

APPROVE Appropriation and Revenue Adjustment No. 5045 authorizing the transfer of appropriations in the amount of $60,842 for FY 2021-22 from the Senior Nutrition Program Fund (0450) to the General Services - Fleet Operations (0064) for the purchase of a vehicle for the Senior Nutrition Program.

FISCAL IMPACT:

This action increases appropriations in the Fleet Internal Service Fund (0064) and reduces appropriations in the Senior Nutrition Program (0450) by $60,842.00. Allocation adjustments through a T/C 24 will facilitate the fund transfer to the proper disbursement account. The new vehicle will be fully funded by grant dollars through the Older Americans Act. No County general funds will be used.

BACKGROUND:

The Senior Nutrition Program (SNP) within the Public Health Division of Contra Costa Health Services operates to provide free home delivered and congregate meals to underserved and food insecure seniors, many of whom live in food deserts and/or are unable to afford nutritious meals. More than 2,000 homebound seniors over 60 years old receive home delivered meals at least five days a week through the Senior Nutrition Program and receive regular check-ins to increase social support as well as receive nutrition education. On average, 19,000 meals are delivered each month across the County.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Sara Cortez, (925) 787-5874

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Stacey M. Boyd, Deputy

cc: Christine Austin, Sara Cortez

BACKGROUND: (CONT'D)

The Senior Nutrition Program receives Federal funds through the Older American's Act, which aims to improve the health and well-being of Seniors throughout the State. The purchase of this vehicle will allow SNP to keep up with the demand of home delivered meals to homebound seniors and add additional capacity to keep up with the rise in home delivered meals due to the Covid-19 pandemic, which has impacted seniors and their ability to safely attend congregate meals.

CONSEQUENCE OF NEGATIVE ACTION:

If this appropriation adjustment is not approved, this will have an impact on the Senior Nutrition Program's ability to keep up with the volume of home delivered meals and could adversely impact services, routes and meeting the need of food insecure and medically vulnerable seniors.

AGENDA ATTACHMENTS

TC24/27 AP005045

MINUTES ATTACHMENTS

Signed: Appropriations & Adjustment No. 5045

AUDITOR-CONTROLLER USE ONLY

FINAL APPROVAL NEEDED BY:

[x] BOARD OF SUPERVISORS

[x] COUNTY ADMINISTRATOR

[x] AUDITOR-CONTROLLER

CONTRA COSTA COUNTY
APPROPRIATION ADJUSTMENT / ALLOCATION ADJUSTMENT
T/C 27

DEPARTMENT: Health services Public Health (0450) / PW ISF (0064)

ACCOUNT CODING ORGANIZATION	EXPENDITURE SUB-ACCOUNT	EXPENDITURE ACCOUNT DESCRIPTION	<DECREASE>		INCREASE	
4284	4953	Auto & Trucks			60,842	00
5750	2310	Non-Cty Prof Spclzd Svcs	60,842	00		
5750	5011	Reimbursements-Gov/Gov			60,842	00
		TOTALS	60,842	00	121,684	00

APPROVED

AUDITOR-CONTROLLER:

BY: [signature] DATE 4/20/22

COUNTY ADMINISTRATOR:

BY: Enid Mendoza DATE 4/27/22

BOARD OF SUPERVISORS:

YES:

NO:

BY: ______ DATE ______

EXPLANATION OF REQUEST:

To transfer appropriation from Public Health to Fleet Services for a vehicle for the Senior Nutrition Program.

[signature] 4/14/2022

SIGNATURE TITLE DATE

APPROPRIATION APOO 5045

ADJ. JOURNAL NO.

(M129 Rev 05/09)

AUDITOR-CONTROLLER USE ONLY

FINAL APPROVAL NEEDED BY:

[x] BOARD OF SUPERVISORS

[x] COUNTY ADMINISTRATOR

[x] AUDITOR-CONTROLLER

CONTRA COSTA COUNTY
ESTIMATED REVENUE ADJUSTMENT/ ALLOCATION ADJUSTMENT
T/C 24

ACCOUNT CODING — DEPARTMENT : Public Works ISF (0064)

ORGANIZATION	REVENUE ACCOUNT	REVENUE ACCOUNT DESCRIPTION	INCREASE		<DECREASE>	
4284	9951	Reimbursements - Gov/Gov	60,842	00		00
		TOTALS	60,842	00	0	00

APPROVED

AUDITOR-CONTROLLER:

BY: [signature] DATE 4/20/22

COUNTY ADMINISTRATOR:

BY: Enid Mendoza DATE 4/27/22

BOARD OF SUPERVISORS:

YES:

NO:

BY:________ DATE________

EXPLANATION OF REQUEST:

To transfer appropriation from Public Health to Fleet Services for a vehicle for the Senior Nutrition Program.

[signature] 4/14/2022

SIGNATURE TITLE DATE

REVENUE ADJ. RA00 5045

JOURNAL NO.

(M8134 Rev 05/09)

CONTRA COSTA COUNTY
APPROPRIATION ADJUSTMENT /
ALLOCATION ADJUSTMENT
T/C 27

AUDITOR-CONTROLLER USE ONLY
FINAL APPROVAL NEEDED BY:
[x] BOARD OF SUPERVISORS
[x] COUNTY ADMINISTRATOR
[x] AUDITOR-CONTROLLER

DEPARTMENT: Health services Public Health (0450) / PW ISF (0064)

ACCOUNT CODING ORGANIZATION	EXPENDITURE SUB-ACCOUNT	EXPENDITURE ACCOUNT DESCRIPTION	<DECREASE>		INCREASE	
4284	4953	Auto & Trucks			60,842	00
5750	2310	Non-Cty Prof Spclzd Svcs	60,842	00		
5750	5011	Reimbursements-Gov/Gov			60,842	00
		TOTALS	60,842	00	121,684	00

APPROVED

AUDITOR-CONTROLLER:
BY: [signature] DATE 4/20/22

COUNTY ADMINISTRATOR:
BY: Enid Mendoza DATE 4/27/22

BOARD OF SUPERVISORS:

YES: Gioia, Andersen, Burgis, Mitchoff, Glover

NO: None

BY: Stacy M. Boyd DATE 5/3/2022

(M129 Rev 05/09)

EXPLANATION OF REQUEST:

To transfer appropriation from Public Health to Fleet Services for a vehicle for the Senior Nutrition Program.

SIGNATURE [signature] TITLE DATE 4/14/2022

APPROPRIATION APOO 5045
ADJ. JOURNAL NO.

AUDITOR-CONTROLLER USE ONLY
FINAL APPROVAL NEEDED BY:
[x] BOARD OF SUPERVISORS
[x] COUNTY ADMINISTRATOR
[x] AUDITOR-CONTROLLER

CONTRA COSTA COUNTY
ESTIMATED REVENUE ADJUSTMENT/ ALLOCATION ADJUSTMENT
T/C 24

DEPARTMENT: Public Works ISF (0064)

ACCOUNT CODING ORGANIZATION	REVENUE ACCOUNT	REVENUE ACCOUNT DESCRIPTION	INCREASE		<DECREASE>	
4284	9951	Reimbursements - Gov/Gov	60,842	00		00
		TOTALS	60,842	00	0	00

APPROVED

AUDITOR-CONTROLLER:
BY: [signature] DATE 4/26/22

COUNTY ADMINISTRATOR:
BY: [signature] DATE 4/27/22

BOARD OF SUPERVISORS:

YES: Gioia, Andersen, Burgis, Mitchoff, Glover

NO: None

BY: Stacy M Boyd DATE 5/3/2022

(M8134 Rev 05/99)

EXPLANATION OF REQUEST:

To transfer appropriation from Public Health to Fleet Services for a vehicle for the Senior Nutrition Program.

[signature] 4/14/2022
SIGNATURE TITLE DATE

REVENUE ADJ. RA00 5045
JOURNAL NO.

To: Board of Supervisors

From: Diana Becton, District Attorney

Date: May 3, 2022

Contra Costa County

Subject: Add two (2) part-time Deputy District Attorney positions and cancel one (1) vacant Deputy District Attorney

RECOMMENDATION(S):

ADOPT Position Adjustment Resolution No. 25931 to add one (1) part-time (20/40) Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91), add one (1) part-time (20/40) Deputy District Attorney - Basic (2KTF) (represented) at salary plan and grade MA2 2062 ($12,042.69 - $14,672.84) and cancel one full-time (1) vacant Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91) position #6457 in the District Attorney's Office.

FISCAL IMPACT:

Approval of this request is cost neutral. All costs are budgeted in the District Attorney's Office, General Fund.

BACKGROUND:

The District Attorney's Office has used a Family Leave and Alternative Work Schedule program to help its prosecutors balance the needs of family while meeting operational needs of the department. For this purpose, part-time and job-share positions, where attorneys share a traditional full-time assignment, are made available. The addition of two (2) part-time Deputy District Attorney positions will bring the total to four (4) part-time Deputy District Attorney positions in the District Attorney's Office.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: June McHuen, Deputy

Contact: Jason Chan, (925) 957-2234

cc: Jason Chan, Sylvia Wong Tam

CONSEQUENCE OF NEGATIVE ACTION:

If this action is not approved, the District Attorney's Office will not effectively implement its Family Leave and Alternative Work Schedule program and could impact the retention of experienced attorneys.

AGENDA ATTACHMENTS

P300 25931

MINUTES ATTACHMENTS

Signed P300 25931

POSITION ADJUSTMENT REQUEST

NO. 25931
DATE 4/13/2022

Department District Attorney

Department No./
Budget Unit No. 0242 Org No. 2805 Agency No. 42

Action Requested: Add one (1) part-time (20/40) Deputy District Attorney - Advanced (2KTG) (represented), add one (1) part-time (20/40) Deputy District Attorney - Basic (2KTF) (represented) and cancel one (1) full-time vacant Deputy District Attorney - Advanced (2KTG) (represented) position number 6457.

Proposed Effective Date: 4/27/2022

Classification Questionnaire attached: Yes ☐ No ☒ / Cost is within Department's budget: Yes ☐ No ☐

Total One-Time Costs (non-salary) associated with request: _____

Estimated total cost adjustment (salary / benefits / one time):

Total annual cost $0.00 Net County Cost $0.00

Total this FY $0.00 N.C.C. this FY $0.00

SOURCE OF FUNDING TO OFFSET ADJUSTMENT N/A

Department must initiate necessary adjustment and submit to CAO.
Use additional sheet for further explanations or comments.

Jason Chan, Chief of Admin. Services

(for) Department Head

REVIEWED BY CAO AND RELEASED TO HUMAN RESOURCES DEPARTMENT

SS for Paul Reyes 4/14/2022

Deputy County Administrator Date

HUMAN RESOURCES DEPARTMENT RECOMMENDATIONS DATE 4/20/2022

Add one (1) part-time (20/40) Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91), add one (1) part-time (20/40) Deputy District Attorney - Basic (2KTF) (represented) at salary plan and grade MA2 2062 ($12,042.69 - $14,672.84) and cancel one full-time (1) vacant Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91)

Amend Resolution 71/17 establishing positions and resolutions allocating classes to the Basic / Exempt salary schedule.

Effective: ☒ Day following Board Action.
☐ _____(Date)

Carol Berger 4/20/2022

(for) Director of Human Resources Date

COUNTY ADMINISTRATOR RECOMMENDATION: DATE 4/28/2022

☒ Approve Recommendation of Director of Human Resources
☐ Disapprove Recommendation of Director of Human Resources
☐ Other: ____________________

Paul Reyes

(for) County Administrator

BOARD OF SUPERVISORS ACTION:
Adjustment is APPROVED ☐ DISAPPROVED ☐

Monica Nino, Clerk of the Board of Supervisors
and County Administrator

DATE _____ BY _____

APPROVAL OF THIS ADJUSTMENT CONSTITUTES A PERSONNEL / SALARY RESOLUTION AMENDMENT

POSITION ADJUSTMENT ACTION TO BE COMPLETED BY HUMAN RESOURCES DEPARTMENT FOLLOWING BOARD ACTION
Adjust class(es) / position(s) as follows:

REQUEST FOR PROJECT POSITIONS

Department _____ Date _____ No. _____

1. Project Positions Requested:

2. Explain Specific Duties of Position(s)

3. Name / Purpose of Project and Funding Source (do not use acronyms i.e. SB40 Project or SDSS Funds)

4. Duration of the Project: Start Date _____ End Date _____
   Is funding for a specified period of time (i.e. 2 years) or on a year-to-year basis? Please explain.

5. Project Annual Cost

   a. Salary & Benefits Costs: _____
   b. Support Costs: _____
   (services, supplies, equipment, etc.)

   c. Less revenue or expenditure: _____
   d. Net cost to General or other fund: _____

6. Briefly explain the consequences of not filling the project position(s) in terms of:
   a. potential future costs
   b. legal implications
   c. financial implications
   d. political implications
   e. organizational implications

7. Briefly describe the alternative approaches to delivering the services which you have considered. Indicate why these alternatives were not chosen.

8. Departments requesting new project positions must submit an updated cost benefit analysis of each project position at the halfway point of the project duration. This report is to be submitted to the Human Resources Department, which will forward the report to the Board of Supervisors. Indicate the date that your cost / benefit analysis will be submitted

9. How will the project position(s) be filled?
   ☐ a. Competitive examination(s)
   ☐ b. Existing employment list(s) Which one(s)? _____
   ☐ c. Direct appointment of:
      ☐ 1. Merit System employee who will be placed on leave from current job
      ☐ 2. Non-County employee

   Provide a justification if filling position(s) by C1 or C2

USE ADDITIONAL PAPER IF NECESSARY

POSITION ADJUSTMENT REQUEST

C.14

NO. 25931
DATE 4/13/2022

Department District Attorney

Department No./
Budget Unit No. 0242 Org No. 2805 Agency No. 42

Action Requested: Add one (1) part-time (20/40) Deputy District Attorney - Advanced (2KTG) (represented), add one (1) part-time (20/40) Deputy District Attorney - Basic (2KTF) (represented) and cancel one (1) full-time vacant Deputy District Attorney - Advanced (2KTG) (represented) position number 6457.

Proposed Effective Date: 4/27/2022

Classification Questionnaire attached: Yes ☐ No ☒ / Cost is within Department's budget: Yes ☐ No ☐

Total One-Time Costs (non-salary) associated with request: _____

Estimated total cost adjustment (salary / benefits / one time):

Total annual cost	$0.00	Net County Cost	$0.00
Total this FY	$0.00	N.C.C. this FY	$0.00

SOURCE OF FUNDING TO OFFSET ADJUSTMENT N/A

Department must initiate necessary adjustment and submit to CAO.
Use additional sheet for further explanations or comments.

Jason Chan, Chief of Admin. Services

(for) Department Head

REVIEWED BY CAO AND RELEASED TO HUMAN RESOURCES DEPARTMENT

SS for Paul Reyes — 4/14/2022

Deputy County Administrator — Date

HUMAN RESOURCES DEPARTMENT RECOMMENDATIONS DATE 4/20/2022

Add one (1) part-time (20/40) Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91), add one (1) part-time (20/40) Deputy District Attorney - Basic (2KTF) (represented) at salary plan and grade MA2 2062 ($12,042.69 - $14,672.84) and cancel one full-time (1) vacant Deputy District Attorney - Advanced (2KTG) (represented) at salary plan and grade MA2 2261 ($14,665.45 - $16,187.91)

Amend Resolution 71/17 establishing positions and resolutions allocating classes to the Basic / Exempt salary schedule.

Effective: ☒ Day following Board Action.
☐ _____(Date)

Carol Berger — 4/20/2022

(for) Director of Human Resources — Date

COUNTY ADMINISTRATOR RECOMMENDATION: DATE 4/28/2022

☒ Approve Recommendation of Director of Human Resources
☐ Disapprove Recommendation of Director of Human Resources
☐ Other: ____________________

Paul Reyes

(for) County Administrator

BOARD OF SUPERVISORS ACTION:
Adjustment is APPROVED ☒ ~~DISAPPROVED~~ ☒

Monica Nino, Clerk of the Board of Supervisors and County Administrator

DATE 05-03-2022

BY [signature]

APPROVAL OF THIS ADJUSTMENT CONSTITUTES A PERSONNEL / SALARY RESOLUTION AMENDMENT

POSITION ADJUSTMENT ACTION TO BE COMPLETED BY HUMAN RESOURCES DEPARTMENT FOLLOWING BOARD ACTION
Adjust class(es) / position(s) as follows:

P300 (M347) Rev 3/15/01

To: Board of Supervisors

From: Karen Caoile, Director of Risk Management

Date: May 3, 2022

Contra
Costa
County

Subject: Add one Workers' Compensation Claims Adjuster I Position in Risk Management

RECOMMENDATION(S):
ADOPT Position Adjustment Resolution No. 25922 to add one (1) Workers' Compensation Claims Adjuster I (AJWJ) (represented) at salary plan and grade ZB5-1423 ($5,544.27 - $6,739.09) in the Risk Management Department.

FISCAL IMPACT:
This action will result in reduction of contract costs.

BACKGROUND:
The addition of this position will reduce the costs of using temporary staff as supplemental backup to the Workers' Compensation Unit.

CONSEQUENCE OF NEGATIVE ACTION:
Increased costs and dependency on using specialized temporary staff to process claims in the timely manner as required to satisfy current State regulations.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: June McHuen, Deputy

Contact: Karen Caoile (925) 335-1400

cc: Sharon Brown, Sylvia WongTam

AGENDA
ATTACHMENTS
P300 25922
MINUTES
ATTACHMENTS
Signed P300 25922

POSITION ADJUSTMENT REQUEST

NO. 25922
DATE 3/30/22

Department Risk Management

Department No./
Budget Unit No. 0150 Org No. 1505 Agency No. 02

Action Requested: Add one (1) Workers Compensation Claims Adjuster I in Risk Management.

Proposed Effective Date: 4/26/2022

Classification Questionnaire attached: Yes ☐ No ☐ / Cost is within Department's budget: Yes ☐ No ☐

Total One-Time Costs (non-salary) associated with request: _____

Estimated total cost adjustment (salary / benefits / one time):

Total annual cost	$105,119.00	Net County Cost	$0.00
Total this FY	$17,520.00	N.C.C. this FY	$0.00

SOURCE OF FUNDING TO OFFSET ADJUSTMENT Reduction in contract costs

Department must initiate necessary adjustment and submit to CAO.
Use additional sheet for further explanations or comments.

Karen Caoile

____
(for) Department Head

REVIEWED BY CAO AND RELEASED TO HUMAN RESOURCES DEPARTMENT

L.Strobel 3/30/22

___________________________________ ________________
Deputy County Administrator Date

HUMAN RESOURCES DEPARTMENT RECOMMENDATIONS DATE 4/20/2022

Add one (1) Workers' Compensation Claims Adjuster I (AJWJ) (represented) at salary plan and grade ZB5-1423 ($5,544.27 - $6,739.09) in the Risk Management Department.

Amend Resolution 71/17 establishing positions and resolutions allocating classes to the Basic / Exempt salary schedule.

Effective: ☒ Day following Board Action.
☐ _____(Date)

Carol Berger 4/20/2022

___________________________________ ________________
(for) Director of Human Resources Date

COUNTY ADMINISTRATOR RECOMMENDATION: DATE _____

☐ Approve Recommendation of Director of Human Resources
☐ Disapprove Recommendation of Director of Human Resources
☐ Other: ____

____
(for) County Administrator

BOARD OF SUPERVISORS ACTION:
Adjustment is APPROVED ☐ DISAPPROVED ☐

David J. Twa, Clerk of the Board of Supervisors
and County Administrator

DATE _____ BY _____

APPROVAL OF THIS ADJUSTMENT CONSTITUTES A PERSONNEL / SALARY RESOLUTION AMENDMENT

POSITION ADJUSTMENT ACTION TO BE COMPLETED BY HUMAN RESOURCES DEPARTMENT FOLLOWING BOARD ACTION
Adjust class(es) / position(s) as follows:

REQUEST FOR PROJECT POSITIONS

Department _____ Date 4/20/2022 No. xxxxxx

1. Project Positions Requested:

2. Explain Specific Duties of Position(s)

3. Name / Purpose of Project and Funding Source (do not use acronyms i.e. SB40 Project or SDSS Funds)

4. Duration of the Project: Start Date _____ End Date _____
   Is funding for a specified period of time (i.e. 2 years) or on a year-to-year basis? Please explain.

5. Project Annual Cost

   a. Salary & Benefits Costs: _____ b. Support Costs: _____
   (services, supplies, equipment, etc.)

   c. Less revenue or expenditure: _____ d. Net cost to General or other fund: _____

6. Briefly explain the consequences of not filling the project position(s) in terms of:
   a. potential future costs
   b. legal implications
   c. financial implications
   d. political implications
   e. organizational implications

7. Briefly describe the alternative approaches to delivering the services which you have considered. Indicate why these alternatives were not chosen.

8. Departments requesting new project positions must submit an updated cost benefit analysis of each project position at the halfway point of the project duration. This report is to be submitted to the Human Resources Department, which will forward the report to the Board of Supervisors. Indicate the date that your cost / benefit analysis will be submitted

9. How will the project position(s) be filled?
   - ☐ a. Competitive examination(s)
   - ☐ b. Existing employment list(s) Which one(s)? _____
   - ☐ c. Direct appointment of:
     - ☐ 1. Merit System employee who will be placed on leave from current job
     - ☐ 2. Non-County employee

   Provide a justification if filling position(s) by C1 or C2

USE ADDITIONAL PAPER IF NECESSARY

POSITION ADJUSTMENT REQUEST

NO. 25922
DATE 3/30/22

Department Risk Management

Department No./
Budget Unit No. 0150 Org No. 1505 Agency No. 02

Action Requested: Add one (1) Workers Compensation Claims Adjuster I in Risk Management.

Proposed Effective Date: 4/26/2022

Classification Questionnaire attached: Yes ☐ No ☐ / Cost is within Department's budget: Yes ☐ No ☐

Total One-Time Costs (non-salary) associated with request: _____

Estimated total cost adjustment (salary / benefits / one time):

Total annual cost	$105,119.00	Net County Cost	$0.00
Total this FY	$17,520.00	N.C.C. this FY	$0.00

SOURCE OF FUNDING TO OFFSET ADJUSTMENT Reduction in contract costs

Department must initiate necessary adjustment and submit to CAO.
Use additional sheet for further explanations or comments.

Karen Caoile
(for) Department Head

REVIEWED BY CAO AND RELEASED TO HUMAN RESOURCES DEPARTMENT

L.Strobel — 3/30/22
Deputy County Administrator — Date

HUMAN RESOURCES DEPARTMENT RECOMMENDATIONS DATE 4/20/2022

Add one (1) Workers' Compensation Claims Adjuster I (AJWJ) (represented) at salary plan and grade ZB5-1423 ($5,544.27 - $6,739.09) in the Risk Management Department.

Amend Resolution 71/17 establishing positions and resolutions allocating classes to the Basic / Exempt salary schedule.

Effective: ☒ Day following Board Action.
☐ _____(Date)

Carol Berger — 4/20/2022
(for) Director of Human Resources — Date

COUNTY ADMINISTRATOR RECOMMENDATION: DATE _____

☐ Approve Recommendation of Director of Human Resources
☐ Disapprove Recommendation of Director of Human Resources
☐ Other: ____________________

(for) County Administrator

BOARD OF SUPERVISORS ACTION:
Adjustment is APPROVED ☒ ~~DISAPPROVED~~ ☐

Monica Nino, Clerk of the Board of Supervisors and County Administrator

DATE 05-03-2022

BY [signature]

APPROVAL OF THIS ADJUSTMENT CONSTITUTES A PERSONNEL / SALARY RESOLUTION AMENDMENT

POSITION ADJUSTMENT ACTION TO BE COMPLETED BY HUMAN RESOURCES DEPARTMENT FOLLOWING BOARD ACTION
Adjust class(es) / position(s) as follows:

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra Costa County

Subject: Award Amendment #29-393-34 with the California Department of Public Health, Tuberculosis Control Branch

RECOMMENDATION(S):

1. APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Grant Award Amendment #29-393-34 with the California Department of Public Health, Tuberculosis (TB) Control Branch, to amend Grant Award #29-393-33, to increase the amount payable to the County by $5,000 from $304,417 to a new amount payable of $309,417, with no change in the original term of July 1, 2021 through June 30, 2022; and

2. AUTHORIZE the Purchasing Agent to procure gift cards (up to $20 each) from Safeway, SaveMart, Target, and local gas stations, taxi vouchers, and rent subsidies in a cumulative amount not to exceed $5,000, to be used for food, shelter, incentives and enablers (FSIE), as allowable by the grant allocations.

FISCAL IMPACT:

Approval of this amendment will result in an increase of $5,000 for additional FSIE allotment for FY 2021-2022 from the State of California, TB Control Branch. No County match is required.

BACKGROUND:

The Health Services Department’s Public Health Division maintains a TB Control Program, which serves all reported TB patients and their contacts in Contra Costa County. Outreach services are provided to reach the “Hard-to Reach” people with TB and those at high risk. The TB control staff work within the Communicable Disease Section in collaboration with the HIV/AIDS Program, Substance Abuse Programs, Contra Costa Regional Medical Center and Health Centers, and providers throughout the County. This grant has been awarded to Contra Costa County since 1990.

On June 8, 2021, the Board of Supervisors approved acceptance of Grant Award #29-393-33 with the California Department of Public Health, TB Control Branch, for the TB Control Program, to pay the County an amount of up to $304,417, for the County’s TB control program for the period from July 1, 2021 through June 30, 2022.

Approval of Grant Award

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: Anna Roth, 925 957-2670

cc: Marcy Wilhelm

BACKGROUND: (CONT'D)

Amendment #29-393-34 will allow the Department to receive additional funds for FSIE allotment of $5,000 for clients diagnosed with TB through June 30, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If this contract is not approved, the County will not receive additional funds for services which would result in a decrease in the number of TB patients who receive appropriate FSIE and treatment, therefore increasing the spread of TB.

To: Board of Supervisors

From: David O. Livingston, Sheriff-Coroner

Date: May 3, 2022

Contra Costa County

Subject: California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant

RECOMMENDATION(S):

ADOPT Resolution No. 2022/152 approving and authorizing the Sheriff-Coroner or designee, to apply for and accept a California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant in an initial allocation of $467,210 for the abatement of abandoned vessels and the vessel turn in program on County waterways for the period beginning October 1, 2022 through the end of the grant funding availability.

FISCAL IMPACT:

$467,210; 90% State, 10% County In-kind match (Sheriff Budgeted).

BACKGROUND:

The California Division of Boating and Waterways (DBW) is prepared to award Surrendered and Abandoned Vessel Exchange grant to the Office of the Sheriff to assist the Sheriff's Marine Patrol with the removal of abandoned vessels and water hazards. The funding provided by this grant will enable the Marine Patrol Unit to remove abandoned vessels and identified hazards to vessel navigation in a continued effort to protect life and property on the waterways within Contra Costa County.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Chrystine Robbins, 925-655-0008

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

CONSEQUENCE OF NEGATIVE ACTION:

Negative action on this request will result in the loss of State funding designed to significantly increase the safety and security of persons and
property on the waterways within Contra Costa County.

CHILDREN'S IMPACT STATEMENT:

None.

AGENDA ATTACHMENTS

Resolution 2022/152

MINUTES ATTACHMENTS

Signed Resolution No. 2022/152

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/152

IN THE MATTER OF: Applying for and Accepting the FY 2022/2023 California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant.

WHEREAS, the County of Contra Costa is seeking funds available through the California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant;

NOW, THEREFORE, BE IT RESOLVED that the Board of Supervisors: Authorizes the Sheriff-Coroner, Undersheriff or the Sheriff's Commander, Management Services, to execute for and on behalf of the County of Contra Costa, a public entity established under the laws of the State of California, any action necessary for the purpose of obtaining financial assistance including grant modifications and extensions provided by the State of California for the Surrendered and Abandoned Vessel Exchange Grant.

Contact: Chrystine Robbins, 925-655-0008

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:	0	
ABSENT:	0	
ABSTAIN:	0	
RECUSE:	0	

Resolution No. 2022/152

IN THE MATTER OF: Applying for and Accepting the FY 2022/2023 California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant.

WHEREAS, the County of Contra Costa is seeking funds available through the California Division of Boating and Waterways Surrendered and Abandoned Vessel Exchange Grant;

NOW, THEREFORE, BE IT RESOLVED that the Board of Supervisors: Authorizes the Sheriff-Coroner, Undersheriff or the Sheriff's Commander, Management Services, to execute for and on behalf of the County of Contra Costa, a public entity established under the laws of the State of California, any action necessary for the purpose of obtaining financial assistance including grant modifications and extensions provided by the State of California for the Surrendered and Abandoned Vessel Exchange Grant.

Contact: Chrystine Robbins, 925-655-0008

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

Contra
Costa
County

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Subject: Grant Award #28-994 with the State of California Department of Public Health

RECOMMENDATION(S):
APPROVE and AUTHORIZE the Health Services Director, or designee, to accept Grant Award #28-994 (State Award Number CERI-21-23-08) with the State of California Health and Human Services Agency, California Department of Public Health (CDPH), to pay the County an amount up to $895,271, for the California Equitable Recovery Initiative (CERI) to address COVID-19 health disparities among populations at high-risk and underserved, for the period from September 1, 2021 through June 30, 2023.

FISCAL IMPACT:
Acceptance of the Grant Award will result in funding of up to $895,271 to the County from the CDPH. No County match is required.

BACKGROUND:
The CERI funds are intended to address COVID-19 and advance health equity through strategies, interventions, and services that consider systemic barriers and potentially discriminatory practices that have put certain groups at higher risk for diseases like COVID-19 for disproportionately impacted racial and ethnic groups, rural populations, those experiencing socioeconomic disparities, and other underserved communities within state and local health jurisdictions.

Grant Award #28-994 will allow Contra Costa County's Health Services Department to implement strategies that better position the department to meet COVID-19 response and recovery needs over the next 24 months and prioritize and target resources to those most vulnerable to the impacts of the pandemic.

This grant award was received by the Health Services Department in September 2021, however, the Board Order is being processed late due to an oversight by the Health Services Department's administrative staff.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: Anna Roth, 925-957-2670

cc: Marcy Wilhelm

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra
Costa
County

Subject: Amendment #22–219–69 with Elior, Inc. (dba Trio Community Meals, LLC)

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Amendment #22-219-69 with Elior, Inc. (dba Trio Community Meals, LLC), a limited liability company, to amend Novation Contract #22-219-68, effective January 1, 2022, to modify the rate schedule, with no change in the original payment limit of $4,694,071 or term of July 1, 2021 through June 30, 2022.

FISCAL IMPACT:

No increase to the payment limit is requested. This contract is funded 23%Title III C-1 of the Federal Older Americans Act of 1965, 30% Title III C-2 of the Federal Older Americans Act of 1965, 41% Meals on Wheels of Contra Costa, and 6% Federal and State Emergency funds. No County funds are required. (No rate Increase)

BACKGROUND:

This contractor was selected to provide meals for the Senior Nutrition Program through a competitive bid process. This contract meets the social needs of the County's population. The contractor will prepare and deliver approximately 2,146 prepackaged, frozen meals to County homebound seniors via 22 Meals on Wheels routes and ambulatory seniors through 18 congregate cafes in take-out/home-delivered senior centers throughout the County.

On July 27, 2021, the Board of Supervisors approved Novation Contract #22–219–68 with Bateman Community Living, LLC (dba Trio Community Meals), in an amount of $4,694,071 for the provision of meal services for county's Senior Nutrition Program, for the period from July 1, 2021 through June 30, 2022, which included a three-month automatic extension through September 30, 2022.

On July 9, 2021, the contractor amended their registration with the Sectary of State of California to reflect a name change from Bateman Community Living, LLC to a new name of Elior, Inc. (dba Trio Community Meals, LLC).

Approval of Amendment #22-219-69 will modify the rate schedule and allow the contractor to continue to provide additional meal services through June 30, 2022.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: Ori Tzvieli, M.D. 925-608-5267

cc: marcy.wilham, Alaina Floyd

BACKGROUND: (CONT'D)

This contract request was submitted late due to a delay in obtaining service and budget amounts from the contractor.

CONSEQUENCE OF NEGATIVE ACTION:

If this amendment is not approved, homebound seniors and ambulatory seniors of Contra Costa County participating in the Senior Nutrition Program may not receive the appropriate meals or nutrition.

ATTACHMENTS

Elior Late Memo

ANNA M. ROTH, RN, MS, MPH
HEALTH SERVICES DIRECTOR
ORI TZVIELI, MD
PUBLIC HEALTH DIRECTOR

CONTRA COSTA
HEALTH SERVICES

CONTRA COSTA
PUBLIC HEALTH
597 Center Avenue, Suite 200
Martinez, California 94553
Ph (925) 313-6712
Fax (925) 313-6721

Memo

To:	Anna Roth, RN, MS, MPH, Director of Health Services
From:	Ori Tzvieli, MD, Director of Public Health
Attention:	Tasha Scott, Contracts and Grants Administrator
Re:	Request for retroactive start on amended contract
Date:	April 1, 2022

The Public Health Division requests approval to present a retroactive contract to the Board of Supervisors for the Senior Nutrition Program, this is a new contract, effective March 1, 2022.

The contract is for the provision of congregate meals for the six sites managed by this contract. The contract is for the cost intake and outreach services and related activities. The request for the retro date is not due to a recurring issue. We request approval for a retro start date of March 1, 2022. We do not anticipate this issue reoccurring in the future

Sincerely,

Ori Tzvieli, MD, Director of Public Health

Contra
Costa
County

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Subject: Amendment #74-610-7 with Westcare California, Inc.

RECOMMENDATION(S):
APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Contract Amendment Agreement #74-610-7 with WestCare California, Inc., a non-profit corporation, effective November 1, 2021, to amend Contract #74-610-6 to increase the payment limit by $168,416, from $1,924,519 to a new payment limit of $2,092,935, with no change in the original term of July 1, 2021 through June 30, 2022.

FISCAL IMPACT:
Approval of this amendment will result in additional annual expenditures of up to $168,416 and will be funded 100% by Assembly Bill 109 (AB 109) revenues.

BACKGROUND:
The Behavioral Health Services Department has been contracting with WestCare California, Inc., since October 2019 to provide substance use disorder prevention, treatment, and detoxification treatment services for County residents in West County. This contract meets the social needs of the County's population by providing specialized substance use disorder treatment services, so that men and women, including women with children, are provided an opportunity to achieve and maintain sobriety and to experience the associated benefits of self-sufficiency, family reunification, cessation of criminal activity and productive engagement in the community.

On July 13, 2021, the Board of Supervisors approved Contract #74-610-6, with WestCare California, Inc. for the provision of substance use disorder prevention, treatment and detoxification treatment services for County residents in West County who are referred through the Behavioral Health Access Line, in an amount not to exceed $1,924,519, for the period July 1, 2021 through June 30, 2022.

The delay of this amendment was due to the resurgence of COVID-19 which has created service interruptions, productivity declines and cash flow issues with the community based behavioral health service providers. The contract amendment will allow the department to maintain a viable service delivery network to ensure access to needed behavioral health services within the County.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: Suzanne Tavano, Ph.D., 925-957-5169

cc: E Suisala , M Wilhelm

BACKGROUND: (CONT'D)

Approval of Contract Amendment Agreement #74-610-7 will allow the contractor to continue providing additional substance use disorder prevention, treatment and detoxification services through June 30, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If this amendment is not approved, the County's clients will not receive substance use disorder treatment from this contractor, resulting in an overall reduction of services to a community at risk for incarceration.

CHILDREN'S IMPACT STATEMENT:

This Alcohol and Drug Abuse prevention program supports the Board of Supervisors' community outcomes 4 & 5 by providing individual, group, and family counseling; substance abuse education; rehabilitation support services; and substance abuse prevention services. Expected outcomes include increased knowledge about the impact of addiction; decreased use of alcohol, tobacco and other drugs; increased use of community-based resources; and increased school and community support for youth and parents in recovery.

ATTACHMENTS

To: Board of Supervisors

From: Marla Stuart, Employment and Human Services Director

Date: May 3, 2022

Contra Costa County

Subject: Amend and extend contract with Planet Technologies, Inc. to upgrade STARS (Shared Text Automated Retrieval System)

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Employment and Human Services Director, or designee, to execute a contract amendment, subject to approval as to form by County Counsel, with Planet Technologies, Inc. to increase the payment limit by $215,000 to a new payment limit $314,000, and to extend the term from August 1, 2022 through August 1, 2023 to upgrade the department-wide communication system known as STARS (Shared Text Automated Retrieval System).

FISCAL IMPACT:

$314,000 funded by 5% County, 44% Federal, 51% State revenues as administrative overhead expense, all of which is already budgeted in FY 2021-22 and FY 2022-23.

BACKGROUND:

Employment and Human Services Department (EHSD) is seeking to upgrade its department-wide communication system known as STARS (Shared Text Automated Retrieval System). EHSD's needs have outgrown the out-of-box design for document management, document search and document retrieval used in the initial design. EHSD contracted with Planet Technologies, Inc. (Contractor) to upgrade the existing SharePoint platform to take advantage of efficiencies from automation and

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: C. Youngblood (925) 608-4964

cc: Kathleen Gaughen

BACKGROUND: (CONT'D)

technology advances. The Contractor was involved in the original design of STARS and has successfully delivered pivotal system implementations for EHSD.

The expected outcome of the upgrade is an up-to-date foundation architecture that supports a custom user interface that provides EHSD with the user experience staff need to easily and efficiently provide service to the clients. The current contract for $99,000 is for the foundation architecture modifications. In order to create the required intuitive and user friendly experience for the user interface, the contract must be amended for additional services. The cost increase of $215,000 is necessary to support the key strategic department objective of providing the best in class service to the clients.

CONSEQUENCE OF NEGATIVE ACTION:

The Employment and Human Services Department will be unable to go forward with the communication system upgrade which may have a negative impact to servicing our clients.

Contra Costa County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Construction Contract for the 2022 Countywide Curb Ramp Project

RECOMMENDATION(S):

(1) APPROVE plans, specifications, and design for the 2022 Countywide Curb Ramp Project. (County Project No. 0662-6R4099) (Districts IV, V)

(2) DETERMINE that the bid submitted by Kerex Engineering, Inc. ("Kerex"), has complied with the requirements of the County's Outreach Program and has exceeded the Mandatory Subcontracting Minimum for this project, as provided in the project specifications; and FURTHER DETERMINE that Kerex has submitted the lowest responsive and responsible bid for the project.

(3) AWARD the construction contract for the above project to Kerex in the listed amount ($1,698,315.00) and the unit prices submitted in the bid, and DIRECT that Kerex shall present two good and sufficient surety bonds, as indicated below, and that the Public Works Director, or designee, shall prepare the contract.

(4) ORDER that, after the contractor has signed the contract and returned it, together with the bonds as noted below and any required certificates of insurance or other required documents, and the Public Works Director has reviewed and found them to be sufficient, the Public Works Director, or designee, is authorized to sign the contract for this Board.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Laura Cassell, Deputy

Contact: Adelina Huerta 925-313-2305

cc:

RECOMMENDATION(S): (CONT'D)

(5) ORDER that, in accordance with the project specifications and/or upon signature of the contract by the Public Works Director, or designee, bid bonds posted by the bidders are to be exonerated and any checks or cash submitted for security shall be returned.

(6) ORDER that, the Public Works Director, or designee, is authorized to sign any escrow agreements prepared for this project to permit the direct payment of retentions into escrow or the substitution of securities for moneys withheld by the County to ensure performance under the contract, pursuant to Public Contract Code Section 22300.

(7) DELEGATE, pursuant to Public Contract Code Section 4114, to the Public Works Director, or designee, the Board’s functions under Public Contract Code Sections 4107 and 4110.

(8) DELEGATE, pursuant to Labor Code Section 6705, to the Public Works Director, or to any registered civil or structural engineer employed by the County, the authority to accept detailed plans showing the design of shoring, bracing, sloping, or other provisions to be made for worker protection during trench excavation covered by that section.

(9) DECLARE that, should the award of the contract to Kerex be invalidated for any reason, the Board would not in any event have awarded the contract to any other bidder, but instead would have exercised its discretion to reject all of the bids received. Nothing in this Board Order shall prevent the Board from re-awarding the contract to another bidder in cases where the successful bidder establishes a mistake, refuses to sign the contract, or fails to furnish required bonds or insurance (see Public Contract Code Sections 5100-5107).

FISCAL IMPACT:

100% Local Road Funds

BACKGROUND:

The above project was previously approved by the Board of Supervisors, plans and specifications were filed with the Board, and bids were invited by the Public Works Director. On April 12, 2022 the Public Works Department received bids from the following contractors:

BIDDER, TOTAL AMOUNT, BOND AMOUNTS

Kerex Engineering, Inc.: $1,698,315.00; Payment: $1,698,315.00; Performance: $1,698,315.00

Sposeto Engineering, Inc.: $1,794,408.00

Ghilotti Bros., Inc.: $1,998,350.00

J.J.R Construction, Inc.: $2,022,131.50

FBD Vanguard Construction Inc.: $2,058,901.75

The Public Works Director has reported that Kerex documented an adequate good faith effort to comply with the requirements of the County’s Outreach Program and exceeded the Mandatory Subcontracting Minimum, and the Public Works Director recommends that the construction contract be awarded to Kerex.

The Public Works Director recommends that the bid submitted by Kerex is the lowest responsive and responsible bid, which is $96,093.00 less than the next lowest bid, and this Board concurs and so finds.

The Board of Supervisors previously determined that the project is exempt from the California Environmental Quality Act (CEQA) as a Class 15301(c) Categorical Exemption, and a Notice of Determination was filed with the County Clerk on February 15, 2022.

The general prevailing rates of wages, which shall be the minimum rates paid on this project, have been filed with the Clerk of the Board, and copies will be made available to any party upon request.

CONSEQUENCE OF NEGATIVE ACTION:

Construction of the project would be delayed, and the project might not be built.

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra
Costa
County

Subject: Contract #27-631-9 with Bach-Kim Nguyen, OD (dba Walnut Creek Optometry Group)

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Contract #27-631-9 with Bach-Kim Nguyen, O.D. (dba Walnut Creek Optometry Group), a sole proprietor, in an amount not to exceed $225,000, to provide optometric services to Contra Costa Health Plan (CCHP) members for the period April 1, 2022 through March 31, 2025.

FISCAL IMPACT:

This contract will result in contractual service expenditures of up to $225,000 over a 3-year period and will be funded 100% by CCHP Enterprise Fund II revenues. (No rate increase)

BACKGROUND:

CCHP has an obligation to provide certain specialized optometric health care services for its members under the terms of their Individual and Group Health Plan membership contracts with the County. This contractor has been providing optometric services to CCHP members as a part of the CCHP Provider Network since April 1, 2006.

In March 2020, the County Administrator approved and the Purchasing Services Manager executed Contract #27-631-8 with Bach-Kim Nguyen, O.D. (dba Walnut Creek Optometry Group) in the amount of $100,000 to provide optometry services to CCHP members for the period April 1, 2020 through March 31, 2022.

Approval of Contract #27-631-9 will allow the contractor to continue providing optometric services to CCHP members through March 31, 2024.

CONSEQUENCE OF NEGATIVE ACTION:

If this contract is not approved, certain specialized optometric health care services for CCHP members under the terms of their Individual and Group Health Plan membership contracts with the County will not be provided by this contractor.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Sharron Mackey, 925-313-6104

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc: K Cyr, M Wilhelm

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra Costa County

Subject: Amendment #24–429–77 with Ujima Family Recovery Services

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Contract Amendment #24–429–77 with Ujima Family Recovery Services, a non-profit corporation, effective April 1, 2022, to amend Contract #24-429-72, (as amended by Amendment Agreement #24-429-73 through #24-429-75), to modify the rates for residential and outpatient treatment for pregnant and parenting women and their young children, with no change in the original payment limit of $3,273,091, and no change in the original term of July 1, 2021 through June 30, 2022.

FISCAL IMPACT:

Approval of this contract will result in no change to the original budgeted expenditures of up to $3,273,091 and will be funded by 78% Drug Medi-Cal ($2,551,894); 10% Substance Abuse Prevention and Treatment (SAPT) Perinatal Set-Aside ($295,929); 9% SAPT Block Grant ($321,345) and 3% Assembly Bill (AB) 109 ($103,923) revenues.

BACKGROUND:

The Behavioral Health Services Department has been contracting with Ujima Family Recovery Services, since April 2017 to provide residential and outpatient treatment for pregnant and parenting women and their young children. This contract meets the social needs of the County's population by providing family-centered alcohol and drug treatment services to pregnant and parenting women and their children, in order to prevent perinatal substance abuse and improve birth outcomes. On June 8, 2021, the Board of Supervisors approved Contract #24–429–72, with Ujima Family Recovery Services to provide residential and outpatient treatment for pregnant and parenting women and their young children, in amount not to exceed $3,273,091, for the period from July 1, 2021 through June 30, 2022.In October 2021, the County Administrator approved and the Purchasing Services Manager executed Administrative Agreement #24–429–73, to allow for non-material changes to the payment provisions and fee schedule, to reflect the intent of the parties, with no change in the original payment limit of $3,273,091, and no change in the original term of July 1, 2021 through June 30, 2022. On February 1, 2022, the Board

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Suzanne Tavano, Ph.D., 925-957-5169

cc: E Suisala , M Wilhelm

BACKGROUND: (CONT'D)

of Supervisors approved Amendment Agreement #24–429–74, to modify rates for residential treatment for pregnant and parenting women and their young children, with no change in the original payment limit of $3,273,091, and no change in the original term of July 1, 2021 through June 30, 2022. On April 12, 2022, the Board of Supervisors approved Amendment Agreement #24–429–75, to modify rates for residential treatment for pregnant and parenting women and their young children, with no change in the original payment limit of $3,273,091, and no change in the original term of July 1, 2021 through June 30, 2022. Approval of Contract #24–429–77 will modify the rates for residential treatment for pregnant and parenting women and their young childrent, allowing this contractor to continue to provide services through June 30, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If this amendment is not approved, the residents of Contra Costa County may experience reduced or discontinued behavioral health services.

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra Costa County

Subject: Amendment #74-174-44 with Bi-Bett

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Contract Amendment Agreement #74-174-44 with Bi-Bett, a non-profit corporation, effective April 1, 2022, to amend Contract #74-174-39, (as amended by Amendment Agreements #74-174-40 through #74-174-43) to modify the rates for outpatient substance use disorder prevention, treatment, and detoxification services, with no change in the original payment limit of $5,232,481, and no change in the original term of July 1, 2021 through June 30, 2022.

FISCAL IMPACT:

Approval of this amendment will result in no change to the original budgeted expenditures of up to $5,232,481 and will be funded by 4% Substance Abuse Treatment and Prevention Block Grant ($218,285); 71% Federal Medi-Cal ($3,731,940); 25% Assembly Bill 109 ($1,282,256) revenues.

BACKGROUND:

The County has been contracting with Bi-Bett since May 2002 to provide substance use disorder treatment services for county residents referred through the Behavioral Health Access Line. This contract meets the social needs of the County's population by providing specialized substance use disorder treatment services so that men and women, including women with children, are provided an opportunity to achieve and maintain sobriety and to experience the associated benefits of self-sufficiency, family reunification, cessation of criminal activity and productive engagement in the community.

On July 27, 2021, the Board of Supervisors approved Contract #74–174–39, with Bi-Bett, in an amount not to exceed $5,232,481 to provide substance use disorder treatment services for County residents referred through the Behavioral Health Access Line, for the period from July 1, 2021 through June 30, 2022.

On November 23, 2021, the Board of Supervisors approved Contract Amendment Agreement #74–174–40 to modify the rates with no change in the original payment limit of $5,232,481, and no change in the original term of July 1, 2021 through June 30, 2022.

- [x] APPROVE
- [ ] OTHER
- [x] RECOMMENDATION OF CNTY ADMINISTRATOR
- [ ] RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** [x] APPROVED AS RECOMMENDED [ ] OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

RECUSE: Candace Andersen, District II Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: June McHuen, Deputy

Contact: Suzanne Tavano, Ph.D., 925-957-5169

cc: E Suisala , M Wilhelm

BACKGROUND: (CONT'D)

On February 1, 2022, the Board of Supervisors approved Amendment Agreement #74-174-42, to modify rates with no change in the original payment limit of $5,232,481, and no change in the original term of July 1, 2021 through June 30, 2022.

On April 12, 2022, the Board of Supervisors approved Amendment Agreement #74-174-43, to modify rates with no change in the original payment limit of $5,232,481, and no change in the original term of July 1, 2021 through June 30, 2022.

Approval of Amendment #74-174-44 will modify the rates for outpatient substance use distorder prevention, treatment, and detoxification services, allowing this contractor to continue providing services through June 30, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If this amendment is not approved, the residents of Contra Costa County may experience reduced or discontinued behavioral health services.

Contra Costa County

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Subject: Amendment #74-222-13 with J Cole Recovery Homes, Inc.

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Health Services Director, or designee, to execute on behalf of the County Contract Amendment #74-222-13 with J Cole Recovery Homes, Inc., a corporation, effective April 1, 2022, to amend Contract #74-222-11, (as amended by Amendment Agreement #74-222-12), to modify the rates for residential substance abuse use disorder treatment services for male offenders in East Contra Costa County, with no change in the original payment limit of $934,893, and no change in the original term of July 1, 2021 through June 30, 2022.

FISCAL IMPACT:

Approval of this contract will result in no changes to the original budgeted expenditures of up to $934,893 and will be funded by 29% Federal Drug Medi-Cal ($266,993); 29% State General Fund ($266,993); 12% Assembly Bill (AB) 109 ($123,325) and 30% Local Revenue Fund ($277,582) revenues.

BACKGROUND:

The Behavioral Health Services Department has been contracting with J Cole Recovery Homes, Inc., since January 2004 to provide residential substance abuse use disorder treatment services for male offenders in East Contra Costa County.

This contract meets the social needs of the County’s population by providing specialized substance abuse treatment services so that adults with co-occurring mental disorders are provided an opportunity to achieve sobriety and recover from the effects of alcohol and other drug use, become self-sufficient, and return to their families as productive individuals.

On July 27, 2021, the Board of Supervisors approved Contract #74-222-11 with J Cole Recovery Homes, Inc., to provide residential substance abuse use disorder treatment services for male offenders in East Contra Costa County in the amount of $934,893 for the period from July 1, 2021 through June 30, 2022.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Suzanne Tavano, Ph.D., 925-957-5169

cc: E Suisala , M Wilhelm

BACKGROUND: (CONT'D)

On February 1, 2022, the Board of Supervisors approved Amendment Agreement #74-222-12, to modify rates for residential substance abuse use disorder treatment services for male offenders in East Contra Costa County, with no change in the original payment limit of $934,893, and no change in the original term of July 1, 2021 through June 30, 2022.

Approval of Amendment #74-222-13 will modify rates for residential substance use disorder treatment services for male offenders in East County, allowing this contractor to continue to provide services through June 30, 2022.

CONSEQUENCE OF NEGATIVE ACTION:

If this amendment is not approved, individuals will not receive alcohol and drug prevention and treatment services they need to maintain sobriety and reduce risk factors.

Contra
Costa
County

To: Board of Supervisors

From: Brian M. Balbas, Public Works Director/Chief Engineer

Date: May 3, 2022

Subject: Contract and Purchase Order with Rosenbauer South Dakota, LLC, for Purchase of a Water Tender

RECOMMENDATION(S):
APPROVE and AUTHORIZE the Purchasing Agent, or designee, to execute, on behalf of the Crockett-Carquinez Fire District, a contract and purchase order with Rosenbauer South Dakota, LLC, in connection with the purchase of a Water Tender.

FISCAL IMPACT:
The total purchase price is $310,687 and $250,000 will be funded through a grant from the Crockett Community Foundation. The remaining $60,687 will be funded with Crockett-Carquinez Fire Protection District Funds.

BACKGROUND:
The Crockett-Carquinez Fire Protection District requires the Rosenbauer 2000 Gallon Water Tender (“New Apparatus”) to replace a 1990 Beck Water Tender. The Beck is approaching the end of its service life and does not meet current standards for exhaust emissions. The National Fire Protection Association (NFPA) Standard 1901 for Automotive Fire Apparatus and Standard 1911 for Inspection, Maintenance, Testing and Retirement of In-Service Automotive Fire Apparatus both recommend front-line apparatus be retired into a reserve status after 15 years of service. This is primarily for safety reasons. Older apparatus do not afford firefighters the same level of

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022
Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Carrie Ricci, 925-313-2235

cc:

BACKGROUND: (CONT'D)

safety as modern apparatus due to cab designs, inherent safety features incorporated into modern apparatus design, modern breaking systems, and other considerations. The New Apparatus will have a direct and immediate impact on reducing maintenance costs and improving firefighter safety. The New Apparatus meets all current safety standards, including low diesel emission requirements. The new Water Tender will have a water capacity of 2000 gallons which is 800 more than the current unit. This unit is the only one of its kind in Western Contra Costa County and anywhere along the I-80 corridor south of Cordelia. A water tender is a vital part of the District’s vegetation fire response as well as rural structures and freeway fires involving large vehicle or battery-powered cars.

The Public Works Department’s Purchasing Division released a Request for Proposals for the new apparatus on July 21, 2021 and received three responses. Rosenbauer met all the bid requirements and was selected as the winning bid.

CONSEQUENCE OF NEGATIVE ACTION:

Crockett-Carquinez Fire Protection District will not be able to purchase the New Apparatus.

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Contra Costa County

Subject: Payments for Services Provided by SJBH, LLC (Dba San Jose Behavioral Health Hospital)

RECOMMENDATION(S):
APPROVE and AUTHORIZE the Auditor-Controller, to pay $5,337 to SJBH, LLC (dba San Jose Behavioral Health Hospital) for the provision of inpatient psychiatric treatment services for Contra Costa County residents who were admitted to this facility during the month of June 2021.

FISCAL IMPACT:
Approval of this retroactive payment will result in a one-time payment of $5,337 and will be funded 100% by Mental Health Realignment funds.

BACKGROUND:
The Behavioral Health division has contracted with SJBH, LLC (dba San Jose Behavioral Health Hospital) for the provision of inpatient psychiatric services to County-referred adults. The County is required by Federal Law to reimburse the hospital for any authorized charges.

In October 2020, the County Administrator approved and the Purchasing Services Manager executed Contract #24-794-15(5) with SJBH, LLC (dba San Jose Behavioral Health Hospital), in an amount not to exceed $195,000 for the period from July 1, 2020 through June 30, 2021, including a six-month automatic extension through December 31, 2021, in an amount not to exceed $97,500, for the provision of inpatient psychiatric treatment services for County referred children, adolescents and adults.

Contra Costa Regional Medical Center (CCRMC) referred patients to SJBH,

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Suzanne Tavano, Ph.D.
925-957-5212

cc: Alaina Floyd, marcy.wilham

BACKGROUND: (CONT'D)

LLC (dba San Jose Behavioral Health Hospital) when CCRMC inpatient psychiatric units became full. There was an unanticipated increase in the need for psychiatric services during the contract term and the contract payment limit was exceeded.

As requested by the County, SJBH, LLC (dba San Jose Behavioral Health Hospital) provided additional inpatient psychiatric treatment services in good faith. The Health Services Department has therefore determined that SJBH, LLC (dba San Jose Behavioral Health Hospital) is entitled to payment for the reasonable value of their services under the equitable relief theory of quantum meruit. That theory provides that where a person has been asked to provide services without a valid contract, and the provider does so to the benefit of the recipient, the provider is entitled to recover reasonable value of those services. As such, the Department recommends that the Board authorize the Auditor-Controller to issue a one-time payment not to exceed $5,337.

CONSEQUENCE OF NEGATIVE ACTION:

If this Board Order is not approved, the contractor will not be paid for services requested by County staff and provided by contractor.

CHILDREN'S IMPACT STATEMENT:

This program supports the following Board of Supervisors' community outcome: "Communities that are Safe and Provide a High Quality of Life for Children and Families". Expected program outcomes include a decrease in the need for inpatient care and placement at a lower level of care.

ATTACHMENTS

Contra
Costa
County

To: Board of Supervisors

From: Deborah R. Cooper, Clerk-Recorder

Date: May 3, 2022

Subject: Refund Overpayment of Documentary Transfer Tax

RECOMMENDATION(S):
APPROVE and AUTHORIZE the Auditor-Controller to issue a refund of overpayment of documentary transfer tax totaling $100,002.10 to specified parties.

FISCAL IMPACT:
The recommendation will result in a reduction of $100,002.10 to the County General Fund: $99,995.50 is from the 2020-2021 fiscal year and $6.60 is from the 2021-2022 fiscal year.

BACKGROUND:
The County Clerk-Recorder received incorrect payment of documentary transfer tax from the following parties in the amounts listed below:

California Community Housing Agency	DOC 2021-0056950 $99,995.50
2999 Oak Road, Suite 710	
Walnut Creek, CA 94597	
eRecording Partners Network	DOC 2021-0257564 $6.60
400 Second Avenue South	
Minneapolis, MN 55401	

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

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ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact:

cc:

CONSEQUENCE OF NEGATIVE ACTION:

Failure to reimburse the parties would cause them to pay more than legally required for documentary transfer tax.

C. 30

Contra Costa County

To: Board of Supervisors

From: Federal D. Glover, District V Supervisor

Date: May 3, 2022

Subject: 2021 Annual Report From Bay Point Municipal Advisory Council

RECOMMENDATION(S):

RECEIVE 2021 Annual Report submitted by the Bay Point Municipal Advisory Council.

FISCAL IMPACT:

None.

BACKGROUND:

On June 18, 2002, the Board of Supervisors adopted Resolution No. 2002/377, which requires that each regular and ongoing board, commission, or committee shall annually report to the Board of Supervisors on its activities, accomplishments, membership attendance, required truing/certification (if any), and proposed work plan or objectives for the following year.
The attached report fulfills this requirement for the Bay Point Municipal Advisory Council.

CONSEQUENCE OF NEGATIVE ACTION:

None.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Vincent Manuel (925) 608-4200

cc:

CHILDREN'S IMPACT STATEMENT:

None.

ATTACHMENTS

Bay Point Municipal Advisory Council - 2021 Annual Report

Bay Point Municipal Advisory Council

Debra Mason, 2021 Chair

Federal Glover, District Supervisor, District V

The Bay Point Municipal Advisory Committee serves as an advisory body to the Contra Costa County Board of Supervisors and the County Planning Agency.

2021 Annual Board Report – Bay Point Municipal Advisory Council

We began 2021 by electing our Officers.
All meeting were conducted via ZOOM this year.

At every MAC meeting we have regular updates from;

- California Highway Patrol
- Contra Costa Sheriff's
- Code Enforcement
- Golden State Water
- Supervisor Glover

Supervisor Glover made sure the MAC had regular updates on COVID and County Health data and protocols.

Reports:

- Community Climate Resiliency District gave a report.
- Envision Contra Costa gave us a report.
- We received an update on the Mixed Use Development on Baily Road
- Update on PG&E pond project
- We welcomed LTC Clover from MOTCO to our community and received an update on the new Access Point coming on Port Chicago Highway
- We had a report on the Active Transportation Plan
- Report from County Health about a new Healthy Stores Healthy Community collaboration

Proposals:

- We heard an update on the proposal for a new storage facility in Bay Point.
- Application for a Commissary and Food Truck Park on Nichols Road.
- Update on Alves Lane Apartment project

It should be noted that the MAC requested presentations from both Ambrose Recreation and Park District and East Bay Regional Park District and both indicated they were unable to attend.

Attendance at MAC meetings:

We were pleased to have members of the community attend almost all of our zoom meetings.

Attendance of MAC members; one member has perfect attendance, two members missed 1 meeting, one member missed 2 meetings, the other three missed more than 2 meetings.

Respectively submitted by 2021 Chair:
Debra Mason

Contra
Costa
County

To: Board of Supervisors

From: Deborah R. Cooper, Clerk-Recorder

Date: May 3, 2022

Subject: DECLARE AND ACCEPT THE RESULTS OF THE APRIL 5, 2022 SPECIAL PRIMARY ELECTION 11TH ASSEMBLY DISTRICT

RECOMMENDATION(S):
DECLARE and ACCEPT the results of the April 5, 2022 Special Primary Election 11th Assembly District.

FISCAL IMPACT:
None

BACKGROUND:
Elections Code section 15372 requires the Elections Official to prepare a Certified Statement of Results of the election and submit to the Governing Body within 30 days of the election. A certified Statement of Votes is attached to this Board Order.

CHILDREN'S IMPACT STATEMENT:
None.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Rosa Mena, 925.335.7806

cc:

ATTACHMENTS

04/05/22 Official Canvass

04/05/22 Official
Certification

Office of the Secretary of State
APRIL 5, 2022, SPECIAL PRIMARY ELECTION
ASSEMBLY DISTRICT 11

OFFICIAL CANVASS

County of Contra Costa

Registered Voters: __________

Number of Precincts: 243

Contact: Travis Ebbert; Helen Nolan

Desk Phone: (925) 335-7827; (925) 335-7808
Cell Phone: (925) 826-7842; (530) 392-6011
or (925) 839-7812

E-mail: travis.ebbert@vote.cccounty.us
helen.nolan@vote.cccounty.us

Candidates/Party	Precinct Votes	Vote-by-Mail Votes	Total Votes
Lori D Wilson Democratic			
Erik Elness (W/I) Republican			
	Precinct Votes	**Vote-by-Mail Votes**	**Total Votes**
SUMMARY OF VOTES CAST			

Complete and FAX to (916) 651-6460

CERTIFICATION OF COUNTY CLERK / REGISTRAR OF VOTERS TO THE RESULTS OF THE CANVASS OF THE APRIL 5, 2022 SPECIAL PRIMARY ELECTION ASSEMBLY DISTRICT 11

STATE OF CALIFORNIA }
COUNTY OF CONTRA COSTA } **ss.**

I, **DEBORAH COOPER**, County Clerk/Registrar of Voters of said county, do hereby certify that, in pursuance to the provisions of Elections Code Section 15300, et seq., I did canvass the results of the votes cast in the April 5, 2022 Special Primary Election held in said County on April 5, 2022, the contest that was submitted to the vote of the voters, and that the Statement of Votes Cast to which this certificate is attached, is full, true and correct.

I hereby set my hand and official seal this 14th day of April 2022, in the County of Contra Costa.

Deborah R. Cooper
County of Contra Costa
State of California

Contra
Costa
County

To: Board of Supervisors

From: Anna Roth, Health Services Director

Date: May 3, 2022

Subject: Clarify Prior Board Action Pertaining to Contracted Services with Bridge Hospice East Bay, LLC

RECOMMENDATION(S):

APPROVE clarification of Board action of February 22, 2022, Item (C.51), which authorized the Health Services Director, or designee, to execute Contract #77-375 with Bridge Hospice East Bay, LLC, a limited liability company, in an amount not to exceed $1,000,000 to provide hospice services for Contra Costa Health Plan (CCHP) members for the period September 1, 2021 through August 31, 2024, to instead reflect to correct term of November 1, 2021 through October 31, 2024.

FISCAL IMPACT:

Approval of this clarification will not result in additional service expenditures.

BACKGROUND:

CCHP has an obligation to provide certain specialized hospice health care services for its members under the terms of their Individual and Group Health Plan membership contracts with the County. Services include, on an as needed basis, but are not limited to: visits from registered nurses, certified home health aides, medical social workers, counseling, palliative radiation, custodial care, and in-home physicians. This contractor has been a part of the CCHP Provider

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Sharron Mackey, 925-313-6104

cc: K Cyr, M Wilhelm

BACKGROUND: (CONT'D)

Network since November 1, 2021.

On September 21, 2021, the Board of Supervisors approved Contract #77-375, with Bridge Hospice East Bay, LLC, in the amount of $300,000 to provide hospice services to CCHP members, for the period September 1, 2021 through August 31, 2024.

On February 9, 2022, the Board of Supervisors approved Item (C.51) to correct the payment limit on Contract #77-375, from $300,000 to the Division's requested payment limit of $1,000,000 with no change in the original term of September 1, 2021 through August 31, 2024.

This Board Order will clarify the negotiated term of the February 9, 2022 Board action, which should have been submitted by department as November 1, 2021 through October 31, 2024. Approval of this clarification will allow the department to finally execute a contract with Bridge Hospice East Bay, LLC with the appropriate payment limit and term.

CONSEQUENCE OF NEGATIVE ACTION:

If the recommendation is not approved, the prior incorrect Board action will stand and the contract term will not be corrected.

Contra Costa County

To: Board of Supervisors

From: David O. Livingston, Sheriff-Coroner

Date: May 3, 2022

Subject: Purchase Order - Hammons Supply Company

RECOMMENDATION(S):

APPROVE and AUTHORIZE the Purchasing Agent to execute, on behalf of the Sheriff-Coroner, a purchase order with Hammons Supply Company, in an amount not to exceed $400,000 for the purchase of custodial supplies and equipment repairs as needed by the three County detention facilities for the period May 1, 2022 through April 30, 2023.

FISCAL IMPACT:

$400,000. 100% General Fund; Budgeted.

BACKGROUND:

Hammons Supply Company provides miscellaneous janitorial products and equipment for Contra Costa County's three detention facilities, West County, Martinez, and Marsh Creek Detention Facilities. Hammons Supply Company offers lower pricing for specific custodial products, such as plastic liners, latex gloves and toilet paper when compared to other major county suppliers. They also have a local warehouse that accommodates quicker delivery and/or pick-up of supplies.

CONSEQUENCE OF NEGATIVE ACTION:

The Sheriff's Office would not be able to purchase the required items to operate the three detention facilities.

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

Contact: Heike Anderson 925-655-0023

cc: Heike Anderson, Alycia Rubio, Paul Reyes

CHILDREN'S IMPACT STATEMENT:

No impact.

Contra Costa County

To: Board of Supervisors

From: Russell Watts, Treasurer-Tax Collector

Date: May 3, 2022

Subject: Postponed Property Tax Sale by the County Tax Collector

RECOMMENDATION(S):

ADOPT Resolution No. 2022/153 authorizing postponement of the Annual Property Tax Sale approved February 22, 2022 by Board Order C.58, to be delayed an additional month until June 29, 2022, as recommended by the Treasurer-Tax Collector.

FISCAL IMPACT:

All costs will be recovered from the proceeds of the sale. Property or property interests that have been offered for sale at least once and where no acceptable bids have been received at the minimum price, the Tax Collector may offer that same property or those interests at the same or next scheduled sale at a minimum price that may be less than the amount of defaulted taxes, delinquent and redemption penalties as specified in R&T §3698.5(a)(1). Should the final selling price at public auction be less than the amount as specified in R&T §3698.5(a)(1), proceeds shall be distributed as specified in R&T §4673.1 & R&T §4674 and any remaining balance to satisfy the amounts as specified in R&T §3698.5(a)(1) may be transferred from the Tax Loss Reserve Fund. (R&T § 4703.2(c).)

☑ APPROVE ☐ OTHER

☑ RECOMMENDATION OF CNTY ADMINISTRATOR ☐ RECOMMENDATION OF BOARD COMMITTEE

Action of Board On: **05/03/2022** ☑ APPROVED AS RECOMMENDED ☐ OTHER

Clerks Notes:

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor
Candace Andersen, District II Supervisor
Diane Burgis, District III Supervisor
Karen Mitchoff, District IV Supervisor
Federal D. Glover, District V Supervisor

Contact: Ronda Boler, (925) 608-9506

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

BACKGROUND:

The Tax Collector has the authority to sell tax-defaulted property that is subject to the power of sale (R&T §3691). Written approval of the Board of Supervisors (R&T § 3694 and 3698) is required to sell property at public auction (R&T §3692) to the highest bidder at the time and place fixed for sale (R&T §3706) Property that has been tax-defaulted for five or more years and is subject to the Tax Collector's power to sell may be sold. All or any portion of a property may be offered for sale, without regard to its boundaries when it became subject to sale (R&T §3691).

The purpose of the sale is to collect unpaid taxes. Offering property for sale achieves this, either by collecting the unpaid taxes from the proceeds of the sale or through redemption by the assessee. Any person or entity, including cities, taxing agencies, revenue districts and the State may purchase property at a public auction (R&T § 3691 and 3705). The only exception to eligible purchasers is the Tax Collector, who conducts the sale, or his/her employees (California Government Code § 1090).

If a parcel is redeemed before the close of business on the last business day prior to the date of sale, the power to sell is automatically nullified and the parcel will be withdrawn from the sale. If a parcel is redeemed within 90 days of the scheduled sale, $150 will be collected to reimburse the County for costs incurred in preparing to conduct the sale (R&T § 4112). Where property or property interests have been offered for sale at least once and no acceptable bids therefore have been received at the minimum price, the tax collector may, in his or her discretion and with the approval of the board of supervisors, offer that same property or those interests at the same or next scheduled sale at a minimum price that the tax collector deems appropriate in light of the most current assessed valuation of that property or those interests, or any unique circumstance with respect to that property or those interests. (R&T § 3698.5(c)) Any parcel remaining unsold may be reoffered within a 90-day period and any new parties of interest shall be notified in accordance with R&T §3706.

As recommended by the Treasurer-Tax Collector, it is necessary to postpone the tax sale another month.

CONSEQUENCE OF NEGATIVE ACTION:

If not approved, the Annual Tax Collector's Public Auction will not proceed and property taxes will not be collected.

AGENDA ATTACHMENTS

Resolution 2022/153

49283_2022 PA SCO Form

MINUTES ATTACHMENTS

Signed Resolution No. 2022/153

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:		
ABSENT:		
ABSTAIN:		
RECUSE:		

Resolution No. 2022/153

Sale of Tax-Defaulted Property by the County Tax Collector

Whereas, the Board, pursuant to §3698 of the Revenue and Taxation code, having been notified by the County Tax Collector of his intent to sell certain tax-defaulted property at public auction and having been provided with a description and minimum purchase price for which each will be sold, and the notice of intended sale of the aforementioned properties be posted or published in accordance with §3702 and §3703 of the California Revenue and Taxation Code.

Now, Therefore, Be It Resolved by the Board that the County Tax Collector's proposed sale of tax-defaulted properties listed in Exhibit A attached hereto and made a part hereof, at or above the minimum price indicated is APPROVED pursuant to §3698 of the Revenue and Taxation Code, and the notice of intended sale be posted or published in accordance with §3702 and §3703 of the Revenue and Taxation Code.

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

Contact: Ronda Boler, (925) 608-9506

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc:

EXHIBIT "A"

WITH APPROVAL OF THE BOARD OF SUPERVISORS, BY RESOLUTION 2022/XX DATED XXXXXX, 2022

Item #	Assessor's Parcel Number (APN) Assessee(s)	Minimum Bid Amount	Default Number Power to Sell Notice Rec. #
1	410-276-016-4	33,900.00	2015-03058
	ZEPEDA MAURO		2021-0284378
4	208-410-073-0	59,100.00	2015-03518
	TAPPIN SHARON		2021-0284384
5	203-850-006-8	226,600.00	2015-04402
	TAPPIN KENNETH		2021-0284385
6	052-014-006-2	27,400.00	2015-00247
	STANGER WILLIAM L		
	CANNON NICKI		2021-0284387
7	430-151-001-4	2,400.00	2015-04769
	SPILLER NEFERAE C		2021-0284391
8	530-330-006-4	6,600.00	2015-01969
	RODRIGUEZ ALEJANDRO		2021-0284388
9	273-083-031-8	13,300.00	2015-03870
	ROACH MICHAEL F & CHRISTINE H		2021-0284389
10	273-083-032-6	12,600.00	2015-03871
	ROACH MICHAEL F & CHRISTINE H		2021-0284390
11	273-083-033-4	11,900.00	2015-03872
	ROACH MICHAEL F & CHRISTINE H		2021-0284392
14	056-280-045-8	53,300.00	2015-00216
	MILLER JAMES		2021-0284361
15	112-033-024-4	26,100.00	2015-00779
	LITTLE THOMAS & REBECCA		2021-0284362
16	540-091-018-7	88,200.00	2015-02152
	LIBERAL CATHOLIC CHURCH OF SF		
	TAMI STEELMAN-GONZALES		2021-0284363
17	417-162-009-1	47,900.00	2015-03117
	LI ANDREW		2021-0284364
18	095-092-007-4	25,800.00	2015-04923
	KHAN FOZIA		2021-0284366
19	095-092-010-8	13,300.00	2015-04924
	KHAN FOZIA		2021-0284367
20	071-012-030-4	4,700.00	2015-00426
	JAUREGUI JAIME R & ISABEL		2021-0284368
21	516-210-009-2	57,000.00	2015-02325
	HOLLEY KAY DEL CARMEN		2021-0284369
22	029-072-016-8	4,700.00	2015-04643
	GREER LAVERN F & JUDY M TRE		2021-0284373
24	408-011-023-4	109,200.00	2015-02061
	GALLOWAY DORIS		
	JOHNSON JAMES R		2021-0284375
25	161-301-025-3	1,700.00	2015-01435
	FONG EDWARD		2021-0284377
26	558-242-008-8	109,700.00	2015-01990
	FOCUS GROUP VENTURES LLC		2021-0284348
27	561-181-013-5	82,500.00	2015-02250
	FIERRO JUAN & SILVIA		2021-0284349
28	260-320-062-3	15,600.00	2015-03804
	FECADU ADAMU		
	SHEAKENA LEMLEM		2021-0284295
29	426-243-039-2	21,100.00	2015-04765
	EDWARDS JOSEPH J		
	EDWARDS LAURA J		2021-0284350
30	402-021-039-1	84,700.00	2015-01534
	EASLEY EDY		2021-0284351
31	142-153-016-1	159,300.00	2015-02711
	EASLEY EDY		
	CONTRERAS NELSON A		2021-0284352
33	152-352-027-6	6,700.00	2015-03202
	C G C LIMITED PARTNERSHIP		
	SIDNEY CORRIE JR		2021-0284337
35	430-162-003-7	55,700.00	2015-04771
	BEACH PARK LLC		2021-0284344
36	032-470-045-9	7,100.00	2015-04064
	BASALLO TED & LIAN GABRIEL		2021-0284345
37	140-372-002-0	43,300.00	2015-02762
	ANDERSON LORI S		2021-0284346
39	550-152-020-8	9,900.00	2014-02460
	WALTON MARY V TRE		
	CLARENCE MARTIN		2021-0284306
40	410-210-042-9	22,400.00	2014-02960
	BREWER DAVID		
	LIPE DEBRA		2021-0284307
42	035-311-012-5	7,400.00	2014-03824
	MARTINEZ JOSEPH & MARY H		
	ANTHONY R MARTINEZ		2021-0284309
43	032-420-040-1	4,700.00	2014-03899
	SCHRIEBER KRISTIAN & TRINITY		2021-0284310
44	365-010-013-8	129,000.00	2014-04305
	MEJIA-MENDEZ MARCOS		
	MEJIA NORA		2021-0284311
46	425-013-019-4	29,100.00	2014-04590
	IRIGOYEN DIEGO		2021-0284313
47	523-023-023-6	63,600.00	2015-01899
	PYLANT GARY		2021-0284314
50	528-280-009-2	46,700.00	2012-01943
	FRENCH MICHAEL		
	FRENCH SALIM A		2021-0284320
		1,724,200.00	

THE BOARD OF SUPERVISORS OF CONTRA COSTA COUNTY, CALIFORNIA

and for Special Districts, Agencies and Authorities Governed by the Board

Adopted this Resolution on 05/03/2022 by the following vote:

AYE:	5	**John Gioia** **Candace Andersen** **Diane Burgis** **Karen Mitchoff** **Federal D. Glover**
NO:	0	
ABSENT:	0	
ABSTAIN:	0	
RECUSE:	0	

Resolution No. 2022/153

Sale of Tax-Defaulted Property by the County Tax Collector

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Contact: Ronda Boler, (925) 608-9506

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: May 3, 2022

Monica Nino, County Administrator and Clerk of the Board of Supervisors

By: Antonia Welty, Deputy

cc: